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Economic Analysis of Coal-Fired Cogeneration Plants for Air Force Bases

R. S. Holcomb
F. P. Griffin

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The Defense Appropriations Act of 1986 requires the Department of Defense to use an additional 1,600,000 tons/year of coal at their U.S. facilities by 1995 and also states that the most economical fuel should be used at each facility. In a previous study of Air Force heating plants burning gas or oil, Oak Ridge National Laboratory found that only a small fraction of this target 1,600,000 tons/year could be achieved by converting the plants where coal is economically viable. To identify projects that would use greater amounts of coal, the economic benefits of installing coal-fired cogeneration plants at 7 candidate Air Force bases were examined in this study. A life-cycle cost analysis was performed that included two types of financing (Air Force and private) and three levels of energy

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Engineering Technology Division

ECONOMIC ANALYSIS OF COAL-FIRED COGENERATION PLANTS FOR AIR FORCE BASES

R. S. Holcomb F. P. Griffin

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ECONOMIC ANALYSIS OF COAL-FIRED COGENERATION PLANTS FOR AIR FORCE BASES

R. S. Holcomb F. P. Griffin

ABSTRACT

The Defense Appropriations Act of 1986 requires the Department of Defense to use an additional 1,600,000 tons/year of coal at their U.S. facilities by 1995 and also states that the most economical fuel should be used at each facility. In a previous study of Air Force heating plants burning gas or oil, Oak Ridge National Laboratory found that only a small fraction of this target 1,600,000 tons/year could be achieved by converting the plants where coal is economically viable. To identify projects that would use greater amounts of coal, the economic benefits of installing coal-fired cogeneration plants at seven candidate Air Force bases were examined in this study. A life-cycle cost analysis was performed that included two types of financing (Air Force and private) and three levels of energy escalation for a total of six economic scenarios. Hill, McGuire, and Plattsburgh Air Force Bases were identified as the facilities with the best potential for coal-fired cogeneration, but the actual cost savings will depend strongly on how the projects are financed and to a lesser extent on future energy escalation rates.

1. EXECUTIVE SUMMARY

1.1 BACKGROUND

The Defense Appropriations Act of 1986 (PL 99-190 Section 8110) instructs the U.S. Department of Defense (DOD) to use an additional 1,600,000 short tons per year of coal at their U.S. facilities by 1995. This act also states that the most economical fuel should be used at each facility. To comply with this act, the United States Air Force requested Oak Ridge National Laboratory (ORNL) to evaluate the feasibility and economics of replacing gas and/or oil firing with coal firing at Air Force heating plants.

In a previous study by ORNL,[1] commercial and near-commercial coal-burning technologies applicable to conversion of Air Force facilities were reviewed. In a second study by ORNL,[2] Air Force heating plants that burn significant quantities of gas and/or oil (annual average >30 MBtu/h) were reviewed to determine a list of candidate sites for conversion to coal. This fuel-use criteria was used in conjunction with a simple economic analysis based on uniform annual costs to develop a list of 16 Air Force sites that could potentially use coal with a cost savings.

In a third report by ORNL,[3] the central heating plants at these 16 bases were evaluated further to determine their relative potential for cost savings through coal utilization. They were ranked according to their suitability for conversion to coal based on a life-cycle cost (LCC) analysis. One conclusion was that only a small fraction of the DOD target of 1,600,000 tons/year of coal can be achieved by converting the heating plants where coal is economically viable. Other types of projects that use greater amounts of coal, such as cogeneration, would have to be considered to realize a larger portion of the DOD target.

1.2 DESCRIPTION

The objective of this study is to analyze the potential economic benefits of installing coal-fired cogeneration plants at selected Air Force bases in each of two categories:

- Installing a new plant at bases where oil or gas is presently the primary heating fuel, and
- Adding a steam turbine generator, or a new high-pressure boiler plus a turbine generator at bases where coal is already the primary heating fuel.

From the list of the 16 leading bases for conversion from gas/oil to coal firing, 4 bases with high electric power rates were selected for analysis of potential cogeneration plants. Three bases that are currently using coal to provide steam for heating were chosen to study the economics of cogeneration.

A cogeneration cycle in which ~20 to 25 MW of electric power would be produced over the entire range of heat load was chosen for each of the seven bases. The cycles were designed so that the maximum electric power is produced at about the annual average heat load, which tends to optimize the turbine generator capacity factor. It is assumed that all power produced by a cogeneration plant would be sold to the electric utility grid. The capacity rating and incremental coal consumption of the plants are shown in Table 1.1.

Table 1.1. Cogeneration plant capacity and projected incremental coal consumption

Base	Present fuel	Cogeneration boiler steam capacity (lb/h)	Generator capacity (MWe)	Incremental coal use (tons/year)
Hill	Gas	250,000	26.0	126,200
McGuire	Gas	250,000	24.7	106,900
Plattsburgh	No. 6 oil	250,000	24.7	108,600
Kelly	Gas	250,000	26.0	122,800
Griffiss	Coal	290,000	29.1	109,300
Grissom	Coal	158,000	15.2	58,300
Wright-Patterson	Coal	450,000[a]	26.0	96,800

[a]Existing boilers are capable of generating high-pressure steam and would be reused.

At the bases now using oil or gas, a completely new coal-fired plant would be required. A new coal-fired plant with a fuel input of 100 MBtu/h or more will be required to meet 90% SO_2 reduction. A circulating fluidized-bed combustion boiler was assumed as the reference design for the new plants because of its excellent environmental control capability and fuel flexibility. Stoker-fired boilers were assumed as the reference design for new high-pressure boilers at bases where coal is already in use.

An economic analysis was performed using an LCC computer model that was developed by modifying the earlier cost model used in the previous heating plant ranking study.[3] The economics were evaluated by calculating a benefit/cost ratio for each proposed cogeneration plant. The benefit/cost ratio is defined as the LCC of the present system for providing heat to the base, divided by the LCC of heat from the cogeneration plant. Two types of financing were examined: (1) Air Force-owned and -financed projects and (2) privately owned and financed projects. The Air Force-financing case was analyzed only to provide a basis for comparison, and it is not anticipated that cogeneration plants would be built with Air Force financing. The LCC was computed for a discount rate of 10% for Air Force financing. For private financing, a return on investment (ROI) of 17% before taxes was assumed. A sensitivity study was also performed using a discount rate of 7% and an ROI of 14%.

The LCC was calculated for three assumed levels of energy escalation: high, medium, and zero. The high escalation level was based on DOD guidelines for energy-dependent economic analyses.[4] The medium level is intermediate between zero and the high level. At some of the bases, the effect on the economics of allowing a capital investment credit for on-base backup electric power was examined. The investment credit assumed was the cost of a backup diesel generating plant of a capacity equal to the lesser of two values: the mission-critical power load for which there is no existing backup power or the minimum monthly average power output of the cogeneration plant.

1.3 RESULTS

The benefit/cost ratio for the seven bases are shown in Table 1.2. With Air Force financing, the benefit exceeds the cost for three of the oil-/gas-fired bases (Hill, McGuire, and Plattsburgh) and one coal-fired base (Griffiss). However, installing a high-pressure boiler for cogeneration at Griffiss would place their new heating boilers on standby. The results for Air Force financing provide only a basis of economic comparison because it is not anticipated that cogeneration plants would be built with Air Force financing.

With private financing, the benefit is less than the cost for all the bases. The great difference between the benefit/cost ratios for Air Force and private financing comes about from the dominant effect of the capital investment cost on the economics. If credit is allowed for

Table 1.2. Economic results for cogeneration

Base	Benefit/cost ratio					
	10% Air Force financing with 3 assumptions for energy escalation			17% Private financing with 3 assumptions for energy escalation		
	High	Medium	Zero	High	Medium	Zero
Hill	2.336	2.184	2.820	0.988	0.810	0.688
McGuire	1.536	1.381	1.675	0.787	0.645	0.562
Plattsburgh	1.352	1.252	1.401	0.757	0.654	0.579
Kelly	1.099	0.942	0.970	0.647	0.525	0.447
Griffiss	1.713	2.553	*a*	0.728	0.831	1.218
Crissom	0.726	0.778	0.934	0.500	0.520	0.562
Wright-Patterson	0.703	0.732	0.832	0.615	0.632	0.676

[a]The LCC of generating heating steam in the cogeneration plant is <0 because the revenue from electricity is greater than the capital, O&M, and fuel costs. The benefit/cost ratio is therefore undefined because the denominator is negative.

on-base backup electric power or if an ROI of 14% were acceptable, private financing of cogeneration would be economical for all levels of energy escalation at Hill.

1.4 RECOMMENDATIONS

Feasibility studies of coal-fired cogeneration plants should be initiated for the three leading candidate bases: Hill, McGuire, and Plattsburgh. The studies should be done in sufficient detail to ensure that all site-specific factors are considered in reaching the final conclusions.

2. INTRODUCTION

ORNL is supporting the Air Force Coal Utilization/Conversion Program by providing the Air Force Engineering and Services Center (AFESC) with a defensible plan to meet the provisions of the Defense Appropriations Act of 1986 (PL 99-190 Section 8110). This Act directs the Air Force to implement the conversion of Air Force central heating plants (steam or hot water) from natural gas and/or oil firing to coal firing if a cost savings can be realized. This directive applies to Air Force installations in the contiguous 48 states and Alaska.

2.1 RELATED WORK

ORNL has been involved in the Air Force Coal Utilization/Conversion Program since 1986. In a previous report by ORNL for AFESC,[1] the full range of commercial and near-commercial coal-burning technologies applicable to the conversion of Air Force central heating plants was reviewed. General descriptions and characterizations of each technology are presented, including the degree of commercialization or development, combustion efficiency, environmental performance, applications, and limitations. The capital and operating costs for these technologies have been estimated for generic or typical heating plant installations. These cost estimates were formulated into algorithms and put into a spreadsheet computer program for use in subsequent studies.

In another ORNL report,[2] Air Force installations currently burning significant quantities of gas and/or oil were reviewed. Experience has shown that small heating plants with an annual average fuel use <30 MBtu/h will be unable to burn coal economically. This fuel use screening criteria was used together with a simple economic analysis based on uniform annual costs to find the installations most suitable for coal use. Heating plants at 16 installations were identified as having enough potential for coal utilization with an economic benefit to warrant further analysis.

The central heating plants at these 16 bases were evaluated further to determine their relative potential for cost savings through coal utilization in a third report by ORNL.[3] They were ranked according to their suitability for conversion to coal, based on an LCC analysis. As many as 12 different coal combustion technologies were analyzed at each Air Force site. Also, two types of financing and three levels of fuel escalation were examined in the analysis for a total of six economic scenarios.

A complementary study for AFESC that examines central heating plants at 34 selected Air Force bases was prepared by ORI Inc. and C. H. Guernsey and Co.[5] Leading candidate heating plants are identified for a few specific coal conversion scenarios. These scenarios fit into two categories: (1) complete conversion of existing heating plants to stoker coal firing by boiler conversion or replacement and (2) building coal-fired cogeneration systems sized to meet peak electric loads. Stoker firing is the only coal technology considered in the ORI Inc./ C. H. Guernsey and Co. report.

2.2 PURPOSE

The Defense Appropriations Act of 1986 sets a target for DOD of 1,600,000 tons/year of additional coal use at their U.S. facilities by 1995. This target will be difficult to achieve if heating plant conversions are the only types of projects considered. The objective of this study is to analyze the potential economic benefits of installing coal-fired cogeneration plants at selected Air Force bases. The cogeneration projects fall into two categories:

- Installing a new plant at bases where oil or gas is presently the primary heating fuel, and
- Adding a steam turbine generator, or a new high-pressure boiler plus a turbine generator at bases where coal is already the primary heating fuel.

The electric power rating of each cogeneration plant was chosen for the study to be large enough so that a significant amount of power would be produced over the entire range of heating load for the base, from low load in the summer to peak load in the winter. In most cases, the electric power produced would be greater than that presently required for the base. The surplus power would therefore have to be sold to the electric utility grid. However, the economic analysis in this study was simplified by assuming that all electricity from a cogeneration system would be sold to the utility grid.

2.3 METHOD

Information about the Air Force bases collected for the previous studies[2,3] on coal conversion was used for the analysis of potential cogeneration plants. This included heat and electric loads, fuel prices, electric power rates, local environmental regulations, and site-specific factors. In some cases, more recent heat load, fuel price, and electric rate data were obtained.

Candidate sites were selected from the 16 bases with oil- or gas-fueled heating plants, which were analyzed for coal conversion in the ranking study. Candidates for the addition of cogeneration at coal-burning bases were also chosen from the 11 major bases where coal is used as a heating fuel. The cogeneration cycle was designed for each candidate base to optimize the turbine generator capacity factor while meeting the variable heating load.

A computer model was developed to calculate the LCCs of a potential cogeneration plant and of the existing method of providing heat. The capital costs of cogeneration plants were estimated from data obtained from various sources about the cost of actual circulating fluidized-bed cogeneration plants that have been built. Operating and maintenance (O&M) costs were estimated using the same basis as that used for the replacement of heating boilers in the ranking study.[3]

Two types of project financing were analyzed in this study. One scenario represents an Air Force-owned project using Military Construction Program (MCP) funds, and the other assumes that a private company builds, owns, and operates the cogeneration plant and sells heat to the base and electric power to the utility grid. Air Force financing was analyzed only to provide a basis for economic comparison because it is not anticipated that cogeneration plants would be built with Air Force financing.

2.4 LIMITATIONS

This study has certain limitations. Some of the site-specific information is either unknown or incomplete; therefore, some possible problems are unknown. Detailed architectural, engineering, and environmental studies will be required before implementing an actual project.

Another factor that cannot be estimated with confidence is the price that the electric utility would pay for the export power from a cogeneration plant. The price would likely be subject to negotiation. Assumptions for each base were made from the best available data.

The future changes in fuel prices cannot be predicted accurately either. The economics of a cogeneration plant with private financing depend primarily on the capital cost and electric power rates and are not strongly influenced by future changes in fuel prices. The economics with Air Force financing are more sensitive to future fuel prices, however. A range of assumptions about escalation of electric and fuel prices was used in the analysis, and these are described in the section on economic analysis.

3. SELECTION OF CANDIDATE BASES FOR COGENERATION PLANTS

3.1 BASES CURRENTLY BURNING OIL/GAS AS HEATING FUEL

In a previous ORNL study[3] for the Air Force, the economics of converting oil- or gas-fired heating plants to coal were analyzed for 16 Air Force sites. This group of bases, listed in Table 3.1, represents the sites having the greatest potential for using coal and thus was chosen as the initial list from which to select candidates to study the siting of coal-fired cogeneration plants.

The major criteria for selecting candidate bases are high electric power rates, high oil or gas prices, low coal prices, and available space for siting a cogeneration plant. For cogeneration plants sized to produce a considerable amount of electric power relative to the thermal

Table 3.1. Bases with the most potential for coal utilization

Base (Command)	Primary fuel	Fuel price ($/MBtu)	Electric rate (¢/kWh)	Coal price ($/MBtu)	Available space for cogeneration plant
Elmendorf (AAC)	Gas	2.05	3.5	1.63	[a]
Hill (AFLC)	Gas	2.81	5.2	1.20	Yes
Kelly (AFLC)	Gas	3.68	5.1	1.87	Yes
Robins (AFLC)	Gas	2.74	4.4	1.77	Yes
Tinker (AFLC)	Gas	2.07	4.8	1.68	Yes
Arnold (AFSC)	Gas	3.97	4.5	1.75	Yes
Hanscom (AFSC)	No. 6	3.67	6.1	2.05	No
Andrews (MAC)	No. 6	3.67	5.0	1.84	Yes
Dover (MAC)	No. 6	3.67	4.4	1.84	Yes
McGuire (MAC)	Gas	3.88	6.0	1.89	Yes
Scott (MAC)	Gas	3.80	4.9	1.24	Yes
Grand Forks (SAC)	No. 6	3.67	4.2	1.48	Yes
Minot (SAC)	Gas	3.60	1.5	1.48	Yes
Pease (SAC)	Gas	3.80	5.3	2.07	Yes
Plattsburgh (SAC)	No. 6	3.67	6.3[b]	1.97	Yes
USAF Academy (AFA)	Gas	2.56	3.6	1.17	Yes

[a]Cogeneration plant is in use.

[b]The value assumed for cogenerated electric power is 6¢/kWh, which is the minimum price set for New York State.

load, the electric power rate has the greatest effect on the economics. The coal price is the second most important economic factor. The value of the electric power must be high to recover the large capital investment in the plant. Beyond that, a lower coal price will help to improve further the economics.

Thus, the leading sites for cogeneration plants can be selected approximately on the basis of the electric power rates. Six bases have electric rates greater than 5¢/kWh: Hill, Kelly, Hanscom, McGuire, Pease, and Plattsburgh. Hanscom was eliminated from consideration because there is inadequate space for a coal-fired plant within a reasonable distance of the central heating distribution system. Pease has been designated to be closed and, thus, is not a candidate. The remaining four bases were chosen for analysis: Hill, Kelly, McGuire, and Plattsburgh.

3.2 BASES CURRENTLY BURNING COAL AS HEATING FUEL

There are 11 Air Force bases currently using coal as the primary fuel for their heating plants. Each of these bases, listed in Table 3.2, was given preliminary consideration as a candidate site for studying the economics of installing a retrofit steam turbine generator, or a new high-pressure boiler plus a turbine generator.

Only one base, Wright-Patterson, has heating boilers with pressure capabilities significantly higher than the pressure employed in the steam distribution system. It was chosen as a candidate site to examine the potential economics for retrofitting a steam turbine generator to the present boilers. Three bases, Eielson, Loring, and Clear, already use cogeneration plants and were eliminated from further consideration. Because Chanute is designated to be closed, it was not chosen for study.

Four of the remaining bases, Malmstrom, K. I. Sawyer, F. E. Warren, and Mountain Home, employ high-temperature hot water (HTHW) heating systems. A cogeneration system would require high-pressure steam extraction and yield less power production; thus, these bases were not chosen as candidates. Grissom and Criffiss use low-pressure steam for

Table 3.2. Bases using coal as the primary heating fuel

Base (Command)	Boiler pressure (psig)	Heat distribution pressure (psig)	Electric rate (¢/kWh)	Coal price ($/MBtu)	Comment
Eielson (AAC)	400 Steam	100 Steam			Cogeneration plant is in use
Wright-Patterson (AFLC)	450 Steam	125 Steam	3.5	1.79	
Chanute (ATC)	200 Steam	150 Steam			Designated to be closed
Griffiss (SAC)	200 Steam	150 Steam	5.7[a]	1.70	
Grissom (SAC)	125 Steam	120 Steam	4.5	1.80	
Loring (SAC)	690 Steam	175 HTHW			Cogeneration plant is in use
Malmstrom (SAC)	400 HTHW	400 HTHW			
K. I. Sawyer (SAC)	400 HTWH	400 HTHW			
F. E. Warren (SAC)	400 HTHW	400 HTHW			
Clear (AFSPACECOM)	620 Steam				Cogeneration plant is in use
Mountain Home (TAC)	400 HTHW	400 HTHW	2.7		

[a]The value assumed for cogenerated electric power is 6¢/kWh, which is the minimum price set for New York State.

heating and were selected as candidate sites to study the option of installing (1) a new high-pressure stoker-fired boiler (or boilers) with about the same total capacity as the existing boilers at the central heating plant and (2) a turbine generator.

4. COGENERATION CYCLE SELECTION FOR BASES CURRENTLY BURNING OIL/GAS

4.1 GENERAL APPROACH

The general approach used in selecting a cogeneration cycle for the bases currently using oil or gas as heating fuel was to (1) choose a plant capacity such that a significant amount of electric power would be produced over the entire range of heating load (from low load in the summer to peak load in the winter) and (2) design the cycle to optimize the turbine generator capacity factor while meeting the variable heating load. This is accomplished by designing the cycle so that the maximum electric power output is reached when the thermal output is nearly equal to the annual average heating load of a base. A cogeneration cycle was devised in which steam from the boiler is expanded through a high-pressure turbine and then part of the steam is extracted for heating and the balance is expanded through a medium-pressure turbine, routed through a moisture separator, and then expanded through a low-pressure turbine to a low-pressure condenser. From 0 to 50% heating load, the boiler steam output and flow through the high-pressure turbine would increase, and the steam flow through the medium and low-pressure turbines would remain constant. The electric power output would reach a maximum at 50% heat load. From 50 to 100% heating load, the boiler steam output and flow through the high-pressure turbine would remain constant, and the flow through the medium- and low-pressure turbines would decrease, causing the power output to decrease over this range of heat load.

The peak heat load for the candidate oil-/gas-fired bases is ~100 MBtu/h. To achieve a reasonably high annual capacity factor for the turbine generator, an electric generating capacity of ~25 MW(e) is required. This combination of heat load and power output dictates a boiler capacity of ~300 MBtu/h or more. A flow sheet and description of the cogeneration cycle are presented below for each of the four bases.

4.2 COAL-FIRED BOILER TECHNOLOGY

A new coal-fired plant with a fuel input of 100 MBtu/h or more is required to meet strict air pollution emission limits, including a requirement for 90% SO_2 reduction. The technology options that are available to meet this SO_2 reduction standard are (1) stoker or pulverized coal firing with a flue gas scrubber or (2) fluidized-bed combustion (FBC) with limestone addition. Each of these technologies were reviewed and evaluated in a previous study by ORNL for the Air Force.[1]

Stoker firing is the technology in use at all but one of the Air Force bases currently burning coal and is commonly used for small- and medium-size industrial boilers. It has the advantage of using a fairly simple coal-handling and -feeding system because double-screened coal is purchased and fed at the same size as it is received. The price for the double-screened coal is somewhat higher than for run-of-mine coal, however. One disadvantage of a stoker-fired boiler is that it can only accept coal with a narrow range of properties, which limits flexibility in future sources of fuel. The capital cost of a stoker-fired field-erected water-tube boiler plant, equipped with a flue gas scrubber, is estimated to be somewhat less than for a pulverized coal plant with a scrubber, or for a circulating FBC plant.

Pulverized coal firing is a well-established technology that is commonly used for large industrial boilers and utility boilers. It has the advantages of a higher combustion efficiency than stoker firing, the ability to burn a somewhat wider range of coal than stokers, and the ability to use run-of-mine coal, which has a lower price. However, the run-of-mine coal must be pulverized, which requires a more complex and expensive coal-handling system, consumes additional electrical power, and requires more maintenance than stoker coal handling. The capital cost of a pulverized coal-fired plant with a flue gas scrubber is estimated to be slightly higher than a stoker-fired plant and about the same as a circulating FBC plant.

FBC is a relatively new technology for burning coal in which the combustion occurs in direct contact with limestone, which effects SO_2 capture. A lower combustion temperature than with stoker or pulverized firing is employed, which yields lower NO_x emissions. Two forms of FBC have been developed: bubbling and circulating systems. The circulating type of system has been successfully demonstrated more widely for the type of application considered here and has some superior characteristics to the bubbling system including lower NO_x emission, higher calcium (limestone) utilization, higher combustion efficiency, and greater fuel flexibility.

The FBC systems can burn a wide range of coals, from low-grade coal, coal waste, and lignite, through all ranks of bituminous coal and anthracite. A number of plants have been built that are operating successfully by burning anthracite culm. A circulating FBC cogeneration plant designed to burn wood, bituminous coal, or anthracite has been built by a private owner under contract to the Army to provide heat to Fort Drum. The only limitation on fuel flexibility is that the FBC plant must be designed initially for the lowest performance coal to be burned so that the fuel and limestone feeding systems and ash-handling system have adequate capacity. Then better grades of coal can usually be burned without any difficulty. The capital cost of a circulating FBC boiler plant is about the same as that of a pulverized coal plant with a flue gas scrubber.

A circulating FBC boiler plant was assumed as the reference design for the economic analysis of cogeneration plants at the bases where oil or gas is presently being used because of its excellent characteristics for environmental control and its fuel flexibility.

4.3 HILL AIR FORCE BASE

4.3.1 Description of Existing Central Heating Plant

Hill Air Force Base (AFB) is located near Ogden, Utah. The main steam plant, Bldg. 260, consists of six 33.5-MBtu/h and two 28.5-MBtu/h water-tube boilers designed for gas/oil firing. The boilers produce 100-psig saturated steam. Natural gas is used as the primary fuel and No. 2 oil is the secondary fuel. The boilers were installed from 1955 through 1975 and are in good condition.

4.3.2 Heating Fuel and Electricity Consumption Data

The fuel consumption for Heating Plant 260 was obtained from Air Force Logistics Command (AFLC) energy consumption records for each month of fiscal year (FY) 1985. The electricity consumption for the industrial section of the base for each month of FY 1985 was also obtained from AFLC records. The fuel consumption at Plant 260 has changed somewhat since FY 1985 because Hill now obtains some of its steam from a municipally owned solid-waste incinerator that began commercial operation in October 1988. The incinerator supplies all of Hill's steam needs during the summer months. This situation was simulated by modifying the FY 1985 data and assuming that fuel consumption at Plant 260 is zero during June through September. The electricity and modified fuel consumption data are given in Table 4.1.

Table 4.1. Heating fuel consumption at Bldg. 260 and industrial electricity consumption at Hill AFB

FY 1985 month	Fuel consumption (MBtu)	Average fuel consumption (MBtu/h)	Electricity consumption (MWh)	Average electricity consumption (MW)
October	125,972	169.3	14,611	19.6
November	133,881	185.9	13,451	18.7
December	137,077	184.2	13,785	18.5
January	154,254	207.3	14,992	20.2
February	154,147	229.3	12,987	19.3
March	127,000[a]	170.7	13,137	17.6
April	77,590	107.8	14,753	20.5
May	125,453	168.6	14,235	19.1
June	0[b]	0[b]	13,619	18.9
July	0[b]	0[b]	16,632	22.4
August	0[b]	0[b]	15,414	20.7
September	0[b]	0[b]	15,666	21.8

[a]Data for Bldg. 260 is not available; consumption was estimated from total industrial fuel use for FY 1986.

[b]The fuel consumption data during the summer months were modified and assumed to be zero to account for a solid waste incinerator that began operation in October 1988.

4.3.3 Cogeneration Cycle Analysis

A cogeneration cycle was devised to optimize the turbine generator capacity factor while meeting the variable heating load. The steam from the boiler is expanded through a high-pressure (HP) turbine, and then part of the steam is extracted for heating and the balance is routed through a low-pressure (LP) turbine to a low-pressure condenser. The cycle flow diagram is shown in Fig. 4.1. A high-pressure (1500-psia) steam cycle was chosen to yield a relatively high ratio of power output to heat output. The temperature of the superheated steam at the turbine inlet was chosen as 840°F, which yields just slightly wet steam (0.25% moisture) at 140 psia at the heating steam extraction point (assuming an isentropic efficiency for the turbine of 85%). The low-pressure exhaust steam moisture limit to avoid blade erosion would be reached at a condenser pressure of ~5 psia, so this value was chosen for analysis. A maximum steam extraction rate for heating of 100,000 lb/h was chosen for analysis. This is less than the peak winter heat load for Bldg. 260 at Hill AFB, but a high thermal capacity factor would be realized. The boiler capacity was selected at 250,000 lb/h at full load.

The strategy for operation of the system would be to vary the boiler steam output from 200,000 lb/h at no heating load to 250,000 lb/h

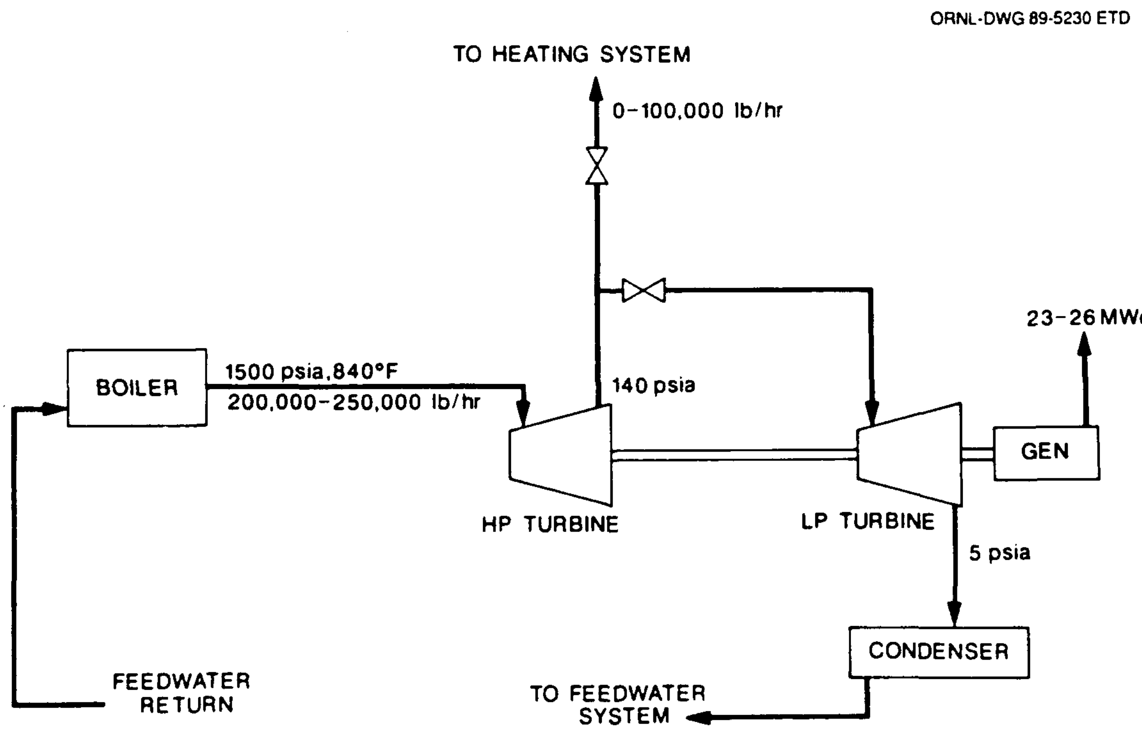

Fig. 4.1. Cogeneration cycle flow diagram for Hill and Kelly AFBs.

at full heating load. From 0 to 50% heating load the boiler steam output and steam flow through the high-pressure turbine would increase from 200,000 to 250,000 lb/h but remain constant at 200,000 lb/h through the low-pressure turbine. From 50 to 100% heating load, the steam flow through the high-pressure turbine would remain constant at 250,000 lb/h but through the low-pressure turbine would decrease from 200,000 to 150,000 lb/h.

The variation of power output with heating load is shown in Fig. 4.2. The turbine generator power output would be about 23.1 MW(e) at no heat load, increase to a maximum value of about 26 MW(e) at 50% heat load, and then decrease to about 23.2 MW(e) at full heat load. The average heat output (assuming 1050 Btu/lb steam) and average power output are shown for each month of the year in Table 4.2. The annual capacity factors are 0.62, 0.85, and 0.89 for heat, electricity, and the boiler, respectively.

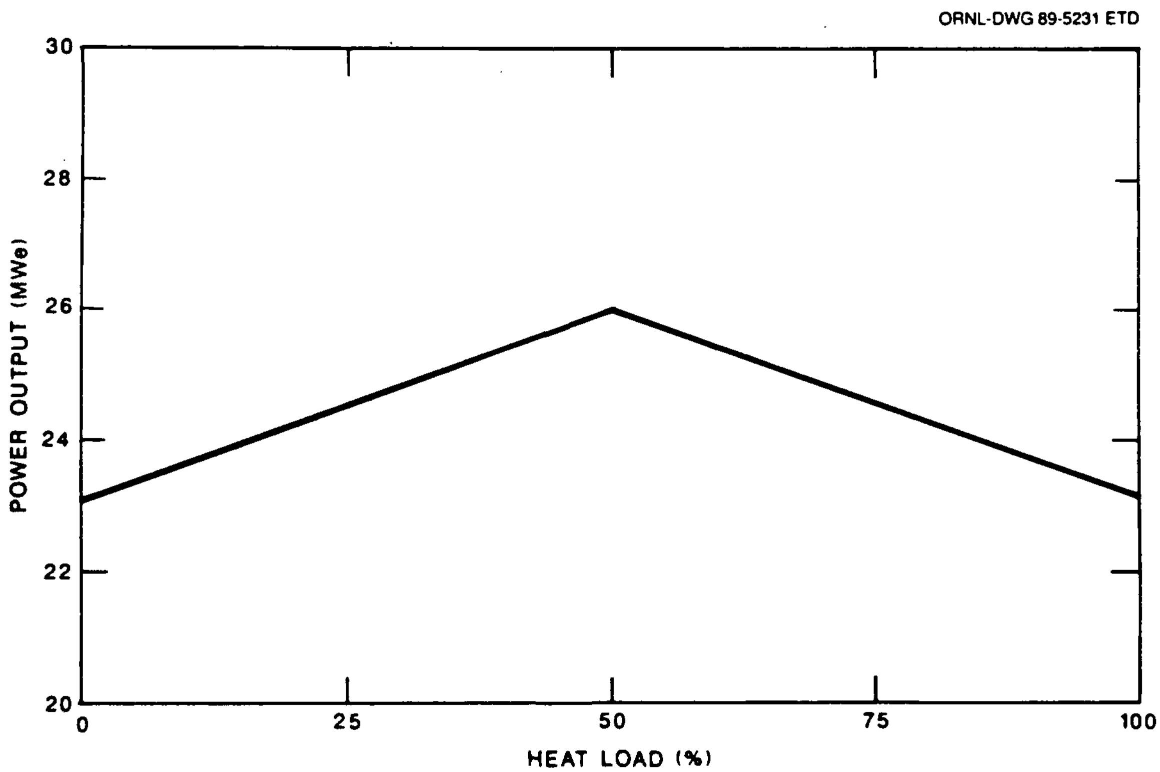

Fig. 4.2. Power output vs heat load for cogeneration cycle applied to Hill and Kelly AFBs.

Table 4.2. Monthly average heat and power output for cogeneration cycle applied to Hill AFB

Month	Average heat output (MBtu/h)	Average power output [MW(e)]
October	105.0	23.2
November	105.0	23.2
December	105.0	23.2
January	105.0	23.2
February	105.0	23.2
March	105.0	23.2
April	85.0	24.3
May	105.0	23.2
June	0.0	23.1
July	0.0	23.1
August	0.0	23.1
September	0.0	23.1

4.4 KELLY AIR FORCE BASE

4.4.1 Description of Existing Central Heating Plant

Kelly AFB is located near San Antonio, Texas. The main steam plant, Bldg. 376, consists of two 54.5-MBtu/h, two 50-MBtu/h, and one 49.6-Btu/h water-tube boilers that were designed for gas/oil firing. The boilers produce 125 psig saturated steam. Natural gas is used as the primary fuel and No. 2 oil is the secondary fuel. The boilers, installed from 1954 through 1976, are in good condition.

4.4.2 Heating Fuel and Electricity Consumption Data

The heating fuel consumption for Heating Plant 376 was estimated for each month from the total base industrial fuel consumption for FY 1986 and the breakdown of the fuel consumption by individual heating plants for FY 1985. The electricity consumption for the base industrial area was obtained from the Defense Energy Information System (DEIS) data for each month of FY 1986. These data are given in Table 4.3.

Table 4.3. Heating fuel consumption at Bldg. 376 and industrial electricity consumption at Kelly AFB

FY 1986 month	Fuel consumption (MBtu)	Average fuel consumption (MBtu/h)	Electricity consumption (MWh)	Average electricity consumption (MW)
October	29,443	39.6	19,034	25.6
November	34,377	47.7	18,257	25.4
December	86,932	116.8	17,904	24.1
January	81,278	109.2	18,787	25.3
February	61,920	92.1	17,390	25.9
March	48,666	65.4	19,431	26.1
April	35,009	48.6	20,606	28.6
May	30,692	41.3	20,810	28.0
June	28,463	39.5	24,360	33.8
July	26,494	35.6	24,670	33.2
August	27,565	37.0	23,516	31.6
September	26,073	36.2	24,646	34.2

4.4.3 Cogeneration Cycle Analysis

The main steam plant, Bldg. 376, at Kelly AFB has characteristics similar to the main steam plant at Hill AFB. The steam pressure at Kelly is 125 psig. The winter heat load at Kelly is somewhat lower than at Hill, but the peak heat load is almost 100 MBtu/h. Therefore, the same cogeneration cycle was used for the study of Kelly and Hill, with identical steam pressures, temperatures, and flow rates, as illustrated in the cycle flow diagram of Fig. 4.1. The average heat output and power output are shown for Kelly for each month of the year in Table 4.4. The annual capacity factors are 0.43, 0.92, and 0.91 for heat, electricity, and the boiler, respectively. Note that the heat output is generally lower than for Hill, matching the lower average heat loads reported for Kelly. The average power output is less than or equal to the average electric load reported for FY 1986, as shown in Table 4.3, indicating that essentially all the power produced could be used by the base.

Table 4.4. Monthly average heat and power output for cogeneration cycle applied to Kelly AFB

Month	Average heat output (MBtu/h)	Average power output [MW(e)]
October	32.3	24.9
November	37.7	25.2
December	95.3	23.7
January	89.1	24.0
February	67.9	25.2
March	53.3	26.0
April	38.4	25.2
May	33.6	25.0
June	31.2	24.8
July	29.0	24.7
August	30.2	24.8
September	28.6	24.7

4.5 McGUIRE AIR FORCE BASE

4.5.1 Description of Existing Central Heating Plant

McGuire AFB is located near Trenton, New Jersey. The main heating plant, Bldg. 2101, consists of four 50-MBtu/h and two 31.2-MBtu/h water-tube boilers that were designed for coal firing but converted to gas/oil firing in 1970. The boilers produce 360°F hot water. Natural gas is used as the primary fuel and No. 2 oil is the secondary fuel. The boilers, installed from 1953 through 1960, are in good condition.

4.5.2 Heating Fuel and Electricity Consumption Data

The heating fuel consumption for the central heat plant was provided by Military Airlift Command (MAC) Headquarters from energy consumption records for each month of FY 1988. The electricity consumption for the base industrial area was obtained from the DEIS data for each month of FY 1985. These data are given in Table 4.5. The electricity consumption is much less than the output of the cogeneration plant concept under study, so most of the electricity produced would be sold to the utility grid.

Table 4.5. Heating fuel consumption at Bldg. 2101 and industrial electricity consumption at McGuire AFB

Month	FY 1988 fuel consumption (MBtu)	Average fuel consumption (MBtu/h)	FY 1985 electricity consumption (MWh)	Average electricity consumption (MW)
October	34,595	46.5	3737	5.0
November	54,996	76.4	3377	4.7
December	66,695	89.6	4543	6.1
January	87,016	117.0	4740	6.4
February	72,843	104.7	4935	7.3
March	65,891	88.6	4830	6.5
April	49,408	68.6	4091	5.7
May	25,238	33.9	3997	5.4
June	16,241	22.6	4777	6.6
July	14,619	19.6	4085	5.5
August	14,009	18.8	5700	7.7
September	17,267	24.0	5136	7.1

4.5.3 *Cogeneration Cycle Analysis*

A cogeneration cycle was chosen for McGuire that is similar to the one for Hill and Kelly except that a steam extraction pressure of 400 psia is used to supply steam to a heat exchanger for heating the high-temperature hot water for the heating distribution system. The cycle flow diagram is shown in Fig. 4.3. The superheated steam conditions at the turbine inlet were chosen as 1500 psia and 720°F to yield just slightly wet steam at the 400-psia heating steam extraction point. The balance of the turbine steam flow is then expanded through an intermediate-pressure turbine to 100 psia, at which point it is routed through a moisture separator. The dried steam is then expanded through a low-pressure turbine to a condenser, which would operate at a pressure of 2 psia, where the exhaust moisture limit would occur.

The boiler steam output would vary from 200,000 to 250,000 lb/h and the heating steam extraction flow from 0 to 100,000 lb/h. The variation of power output with heating load is shown in Fig. 4.4. The turbine generator power output would be about 23.1 MW(e) at no heat load, increase to a maximum value of about 24.7 MW(e) at 50% heat load, and

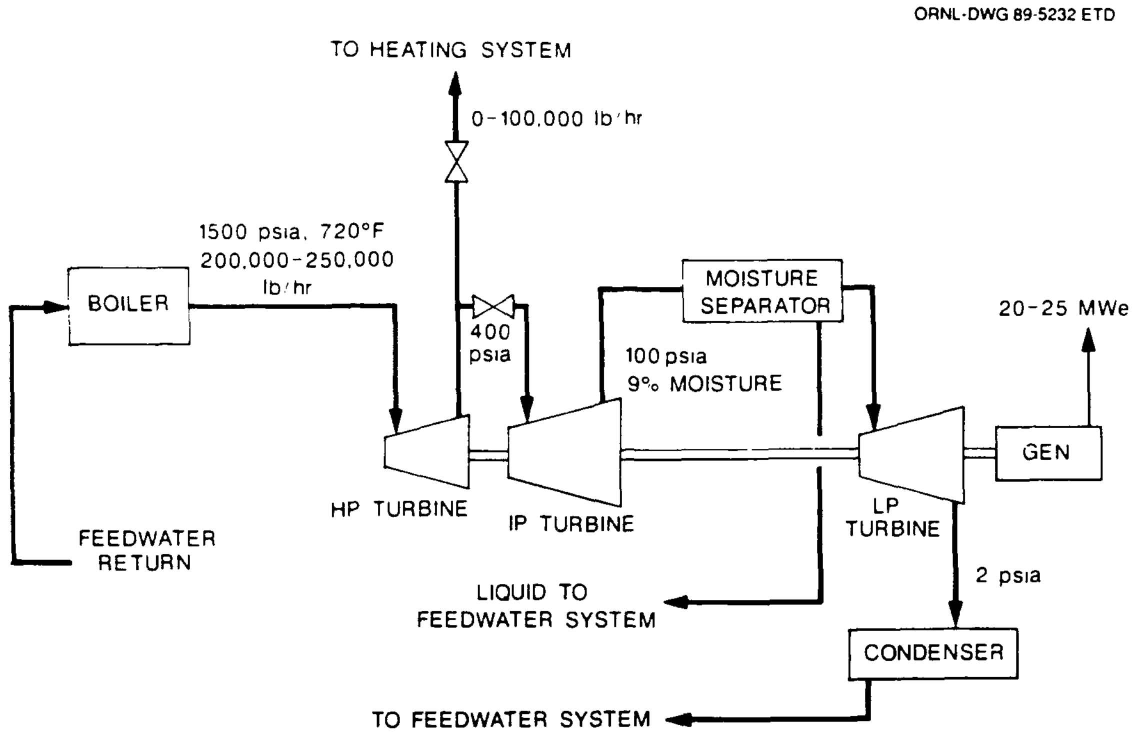

Fig. 4.3. Cogeneration cycle flow diagram for McGuire and Plattsburgh AFBs.

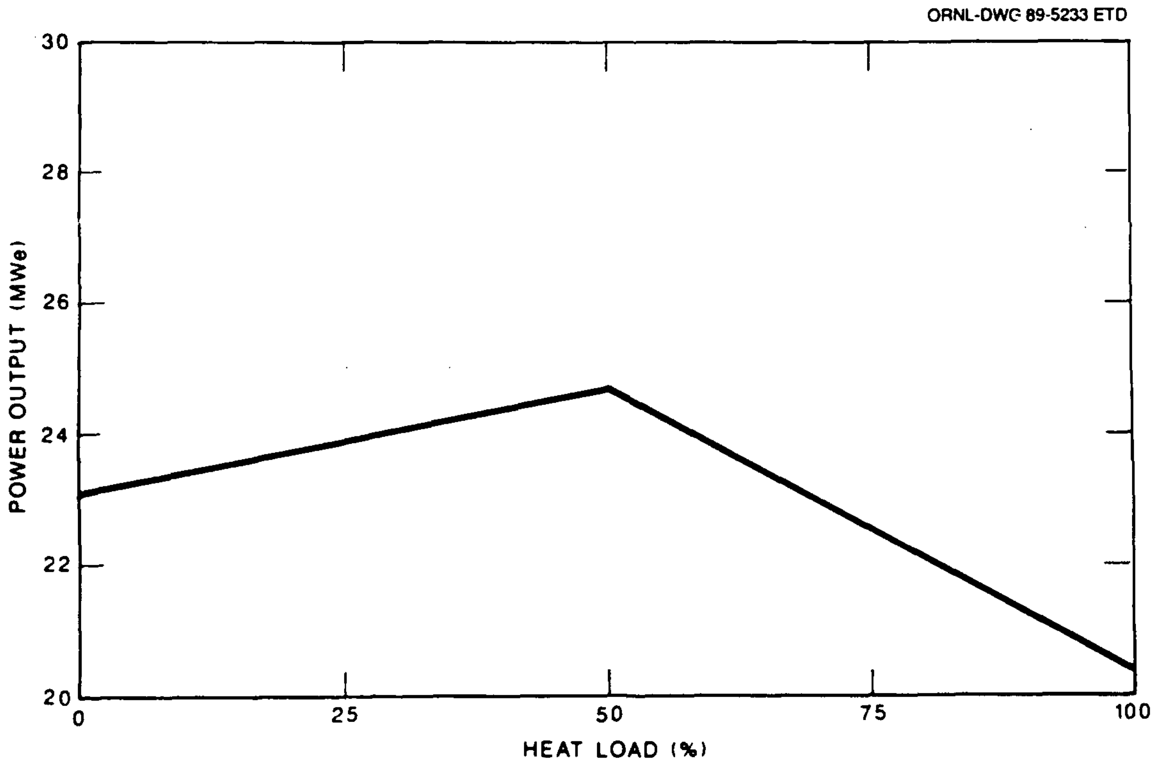

Fig. 4.4. Power output vs heat load for cogeneration cycle applied to McGuire and Plattsburgh AFBs.

then decrease to about 20.4 MW(e) at 100% heat load. The average heat output (assuming 900 Btu/lb steam) and average power output of the proposed cogeneration system are shown for each month of the year in Table 4.6. The annual capacity factors are 0.49, 0.89, and 0.9 for heat, electricity, and the boiler, respectively.

Table 4.6. Monthly average heat and power output for cogeneration cycle applied to McGuire AFB

Month	Average heat output (MBtu/h)	Average power output [MW(e)]
October	37.9	24.4
November	60.3	23.2
December	73.1	22.0
January	90.0	20.4
February	79.8	21.4
March	72.2	22.1
April	54.1	23.8
May	27.7	24.1
June	17.8	23.7
July	16.0	23.7
August	15.4	23.6
September	18.9	23.8

4.6 PLATTSBURGH AIR FORCE BASE

4.6.1 Description of Existing Central Heating Plant

Plattsburgh AFB is located near Plattsburgh, New York. The main heating plant, Bldg. 2658, consists of six 50-MBtu/h water-tube boilers that were designed for No. 6 oil firing. The boilers produce 400°F hot water, and the fuel used is No. 6 oil. The boilers, installed from 1955 through 1957, are in rather poor condition. Replacement boilers and other alternatives are being studied to determine the most economical choice for a future new system.

4.6.2 Heating Fuel and Electricity Consumption Data

The heating fuel consumption data for the central heating plant were provided by Strategic Airlift Command (SAC) Headquarters from energy consumption records for each month of FY 1988. The electricity consumption for the base industrial area was obtained from the DEIS data for each month of FY 1986. These data are given in Table 4.7. Because the electricity consumption is low, most of the electricity produced by the cogeneration plant would be sold to the utility grid.

Table 4.7. Heating fuel consumption at Bldg. 2658 and industrial electricity consumption at Plattsburgh AFB

Month	FY 1988 fuel consumption (MBtu)	Average fuel consumption (MBtu/h)	FY 1986 electricity consumption (MWh)	Average electricity consumption (MW)
October	60,410	81.2	2814	3.8
November	76,070	105.7	2864	4.0
December	90,950	122.2	3404	4.6
January	106,979	143.8	3785	5.1
February	94,284	135.5	3933	5.9
March	90,086	121.1	3588	4.8
April	64,474	89.5	2369	3.3
May	41,435	55.7	2803	3.8
June	25,597	35.6	2521	3.5
July	23,251	31.3	2947	4.0
August	21,950	29.5	2638	3.5
September	29,199	40.6	2363	3.3

4.6.3 Ccgeneration Cycle Analysis

The cogeneration cycle chosen for Plattsburgh is the same as the one analyzed for McGuire, with the same flow rates and cycle conditions as illustrated in Fig. 4.3. Table 4.8 gives the average heat and power outputs for Plattsburgh for each month of the year. The annual capacity factors are 0.65, 0.86, and 0.91 for heat, electricity, and the boiler, respectively. The heat output is a little less than the reported heat

Table 4.8. Monthly average heat and power output for cogeneration cycle applied to Plattsburgh AFB

Month	Average heat output (MBtu/h)	Average power output [MW(e)]
October	66.2	22.7
November	83.4	21.0
December	90.0	20.4
January	90.0	20.4
February	90.0	20.4
March	90.0	20.4
April	70.7	22.2
May	45.4	24.7
June	28.1	24.1
July	25.5	24.0
August	24.1	24.0
September	32.0	24.2

loads for the winter months, but this will yield a higher heating capacity factor for the cogeneration plant, and only a relatively small amount of heat will need to be supplied by an oil-fired peaking boiler.

5. COGENERATION CYCLE SELECTION FOR BASES CURRENTLY BURNING COAL

5.1 GENERAL APPROACH

The same general philosophy was used in designing the cogeneration cycles for bases that are currently burning coal as was used for the bases where oil or gas is in use: produce the maximum electric power at the point where the thermal output is nearly equal to the annual average heating load. Two important differences for the coal-burning bases are (1) the existing boilers are retained where they have the capability to produce steam at a significantly higher pressure than is required for heating use, and (2) if new high-pressure boilers are to be employed, the maximum capacity of the plant is not increased above the capacity of the existing coal-feeding system. Either of these considerations limits the degree to which the ratio of electric power to thermal output can be varied in designing the cogeneration cycle.

5.2 WRIGHT-PATTERSON AIR FORCE BASE

5.2.1 Description of Existing Central Heating Plant

Wright-Patterson AFB is located near Dayton, Ohio. The main steam plant, Bldg. 20770, is composed of three 150-MBtu/h boilers that produce 450-psig saturated steam and two 80-MBtu/h boilers that produce 125-psig saturated steam. They are all stoker-fired water-tube boilers and currently burn bituminous coal. The 450-psig steam produced by the large boilers is converted to 125 psig at Facility 20066 for distribution in the heating system.

5.2.2 Heating Fuel and Electricity Consumption Data

Using the DEIS data, the coal consumption at Bldg. 20770 was estimated from the coal consumption for the entire base for each month of FY 1986. The industrial electricity consumption was also taken from the FY 1986 DEIS data. These data are given in Table 5.1.

Table 5.1. Coal consumption at Bldg. 20770 and industrial electricity consumption at Wright-Patterson AFB

FY 1986 month	Coal consumption (MBtu)	Average coal consumption (MBtu/h)	Electrcity consumption (MWh)	Average electricity consumption (MW)
October	117,180	157.5	27,188	36.5
November	214,200	297.5	26,625	37.0
December	334,800	450.0	24,557	33.0
January	301,320	405.0	27,889	37.5
February	267,840	398.6	24,405	36.3
March	244,627	328.8	26,879	36.1
April	152,136	211.3	26,397	36.7
May	96,400	129.6	27,454	36.9
June	68,400	95.0	31,913	44.3
July	66,960	90.0	33,758	45.4
August	56,767	76.3	34,081	45.8
September	52,200	72.5	28,225	39.2

5.2.3 Cogeneration Cycle Analysis

A cogeneration cycle was designed to utilize the 450-psig steam from the existing boilers. A turbine generator would be added in which the steam from the boilers is expanded through a high-pressure turbine, then part of the steam is extracted at 125 psig for heating, and the balance is routed through a moisture separator and a low-pressure turbine to a condenser. The condenser would operate at a pressure of 5 psia, where the exhaust steam moisture limit would be reached. The flow diagram for the cycle is shown in Fig. 5.1.

The variation of power output with heating load is shown in Fig. 5.2. At zero heat load, the boiler steam output and turbine flow rate would be 300,000 lb/h, and the power output would be about 22.3 MW(e). From 0 to 50% heating load, the boiler steam output and the steam flow through the high-pressure turbine would increase to 450,000 lb/h, and the power output would reach a maximum of 26 MW(e) at 50% heat load. From 50 to 100% heat load, the boiler steam flow and flow through the high-pressure turbine would remain constant while the steam flow through the low-pressure turbine would decrease to 150,000 lb/h, and the

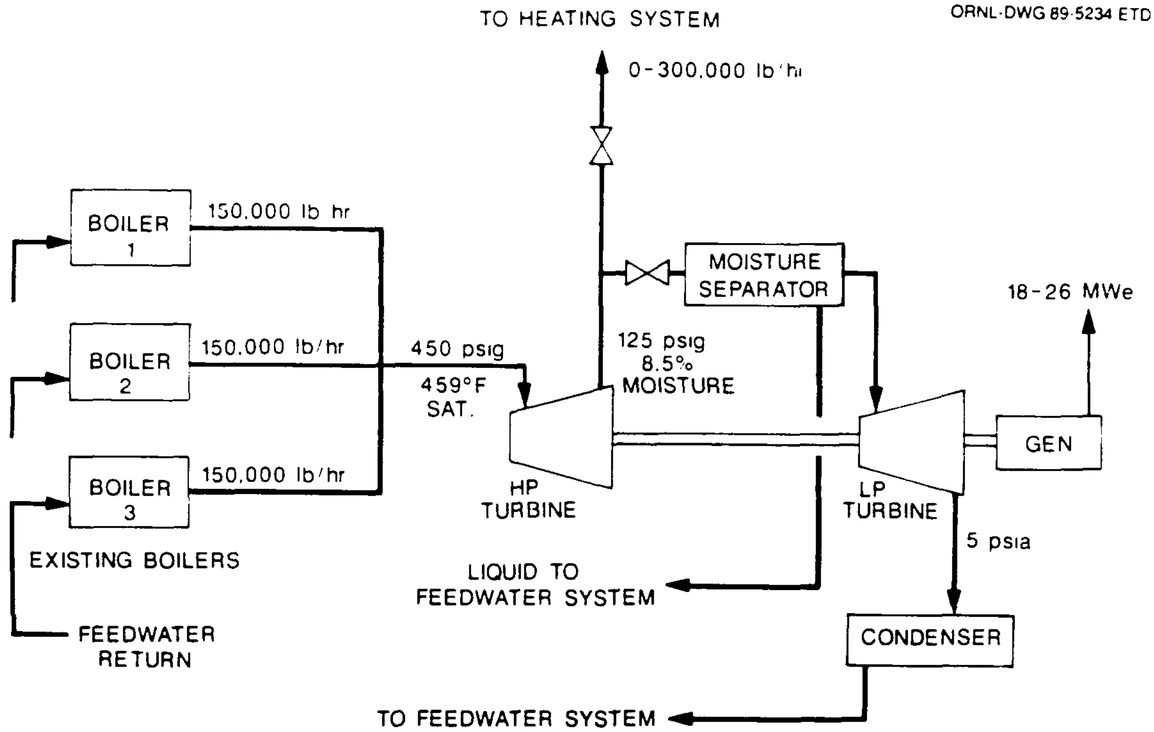

Fig. 5.1. Cogeneration cycle flow diagram for Wright-Patterson AFB.

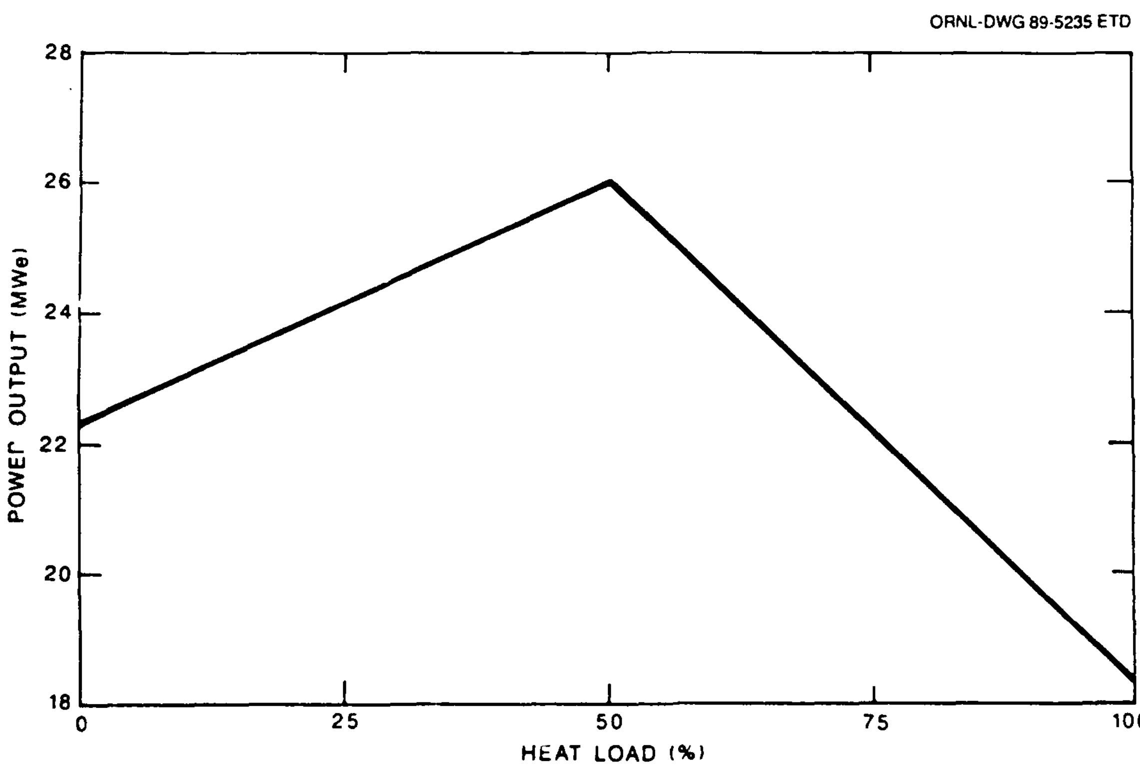

Fig. 5.2. Power output vs heat load for cogeneration cycle applied to Wright-Patterson AFB.

turbine generator power output would decrease to about 18.4 MW(e). The average heat and power output are given for each month of the year in Table 5.2. The annual capacity factors are 0.56, 0.81, and 0.88 for heat, electricity, and the boiler, respectively. The heat output in the winter months is less than the peak load, but the existing 125-psig boilers have sufficient capacity to supply the deficit. The electric power output is less than the base consumption, so all power produced could be used by the base.

Table 5.2. Monthly average heat and power output for cogeneration cycle applied to Wright-Patterson AFB

Month	Average heat output (MBtu/h)	Average power output [MW(e)]
October	128.4	25.6
November	234.7	21.2
December	288.2	18.4
January	288.2	18.4
February	288.2	18.4
March	268.1	19.5
April	166.7	24.8
May	105.6	25.0
June	75.0	24.2
July	73.4	24.2
August	62.2	23.9
September	57.2	23.8

5.3 GRIFFISS AIR FORCE BASE

5.3.1 Description of Existing Central Heating Plant

Griffiss AFB is located near Rome, New York. The central heating plant is composed of four 90-MBtu/h stoker-fired water-tube boilers that produce 150-psig saturated steam. The primary fuel is bituminous coal. The entire coal-fired boiler plant was newly installed in 1985 and is in excellent condition. Spray dryer scrubbers are used for flue gas desulfurization.

5.3.2 Heating Fuel and Electricity Consumption Data

The coal consumption at the central heating plant and the industrial electricity consumption for the base for each month of FY 1986 were obtained from the DEIS data and are given in Table 5.3.

Table 5.3. Coal and industrial electricity consumption at Griffiss AFB

FY 1986 month	Coal consumption (MBtu)	Average coal consumption (MBtu/h)	Electricity consumption (MWh)	Average electricity consumption (MW)
October	72,658	97.7	4,593	6.2
November	94,166	130.8	5,749	8.0
December	104,170	140.0	6,789	9.1
January	108,644	146.0	6,900	9.3
February	100,385	149.4	7,115	10.6
March	89,053	119.7	6,488	8.7
April	69,586	96.6	6,031	8.4
May	24,310	32.7	5,865	7.9
June	0	0	6,343	8.8
July	0	0	5,980	8.0
August	0	0	6,363	8.6
September	9,758	13.6	5,962	8.3

5.3.3 Cogeneration Cycle Analysis

Because the present heating boilers produce low-pressure steam (150 psig), it would be necessary to install a new high-pressure stoker-fired boiler(s), as well as a turbine generator, for cogeneration. A boiler output equal to the present capacity, but with steam conditions of 1500 psia and 820°F at the turbine inlet, was chosen for analysis. The cycle flow diagram is shown in Fig. 5.3. Heating steam is extracted at 165 psia, and the balance of the steam flow is expanded through a low-pressure turbine to a condenser operating at 5 psia.

The boiler steam flow would vary from 235,000 to 290,000 lb/h and the heating steam extraction flow from 0 to 110,000 lb/h. The variation of power output with heating load is shown in Fig. 5.4. The power output varies from about 26.2 MW(e) at no heat load, increases to about

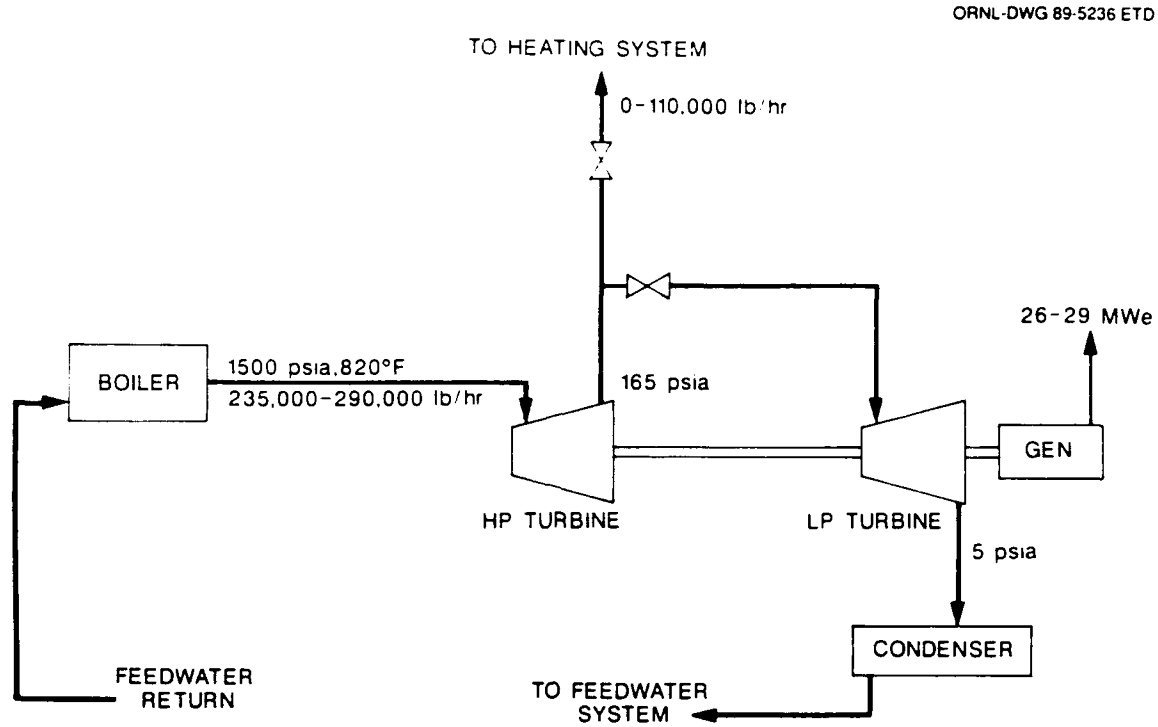

Fig. 5.3. Cogeneration cycle flow diagram for Griffiss AFB.

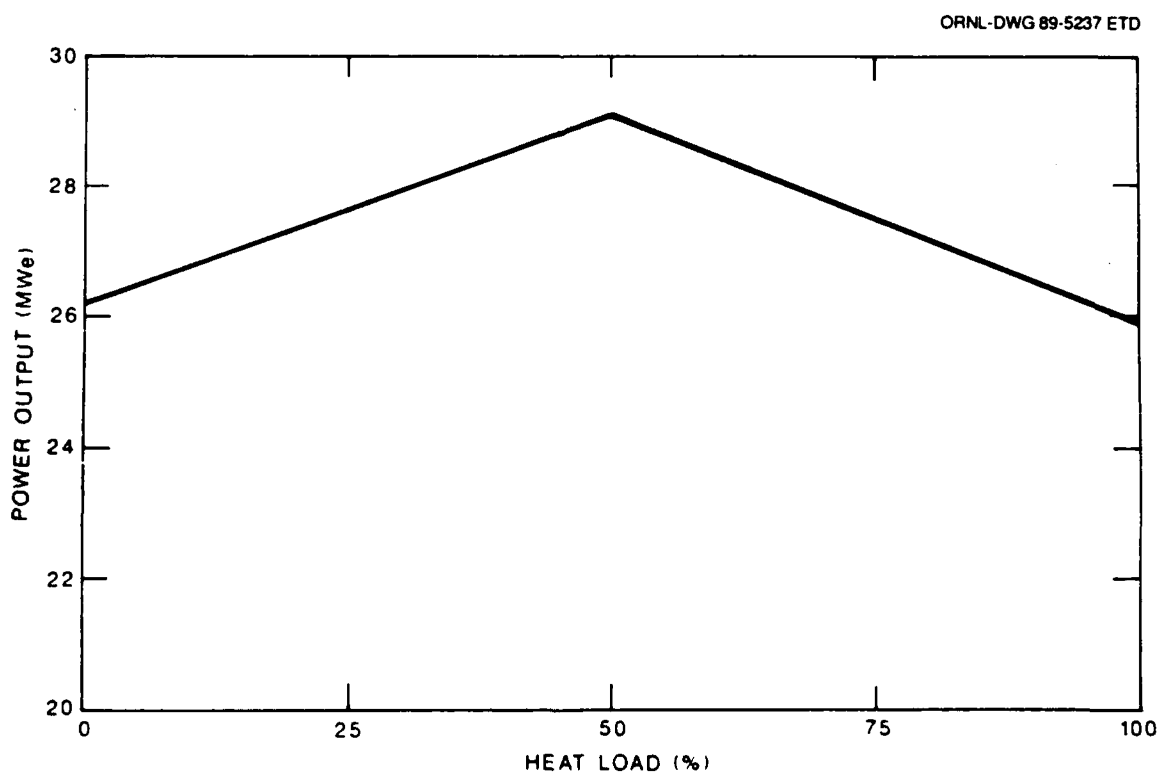

Fig. 5.4. Power output vs heat load for cogeneration cycle applied to Griffiss AFB.

29.1 MW(e) at 50% heat load, and decreases to about 25.9 MW(e) at full heat load. The average heat output (assuming 1050 Btu/lb steam) and average power output are shown for each month of the year in Table 5.4. The annual capacity factors are 0.50, 0.87, and 0.88 for heat, electricity, and the boiler, respectively.

Table 5.4. Monthly average heat and power output for cogeneration cycle applied to Griffiss AFB

Month	Average heat output (MBtu/h)	Average power output [MW(e)]
October	79.6	27.9
November	103.2	26.6
December	114.2	26.0
January	115.5	25.9
February	110.0	26.2
March	97.6	26.9
April	76.3	28.1
May	26.6	27.5
June	0	26.2
July	0	26.2
August	0	26.2
September	10.7	26.7

5.4 GRISSOM AIR FORCE BASE

5.4.1 Description of Existing Central Heating Plant

Grissom AFB is located near Peru, Indiana. The central heating plant, Bldg. 223, consists of two No. 6 oil-fired boilers (both are 35 MBtu/h) and three stoker coal-fired boilers (two are 35 MBtu/h and one is 57 MBtu/h). The boilers produce 125-psig saturated steam. The boilers were installed from 1955 through 1980 and are in good condition. Double alkali-type flue gas scrubbers were installed on the coal-fired boilers, but the plant is presently using low-sulfur bituminous coal, and the scrubbers are not being used because of high particulate emissions from one of them.

5.4.2 Heating Fuel and Electricity Consumption Data

The heating fuel (coal and No. 6 oil) and the industrial electricity consumption for the base for each month of FY 1986 were obtained from the DEIS data and are given in Table 5.5. Most of the heat was supplied from burning coal.

Table 5.5. Heating fuel consumption at Bldg. 223 and industrial electricity consumption at Grissom AFB

FY 1986 month	Coal consumption (MBtu)	No. 6 oil consumption (MBtu)	Combined average fuel consumption (MBtu/h)	Electricity consumption (MWh)	Average electricity consumption (MW)
October	32,937	754	45.3	2,798	3.8
November	44,391	15,963	83.8	2,741	3.8
December	93,084	3,615	130.0	3,706	5.0
January	76,149	7,343	112.2	3,301	4.4
February	68,210	7,764	113.0	3,050	4.5
March	60,368	17,151	104.2	2,993	4.0
April	43,924	5,834	69.1	2,752	3.8
May	2,925	25,532	38.2	2,948	4.0
June	4,596	18,993	32.8	3,339	4.6
July	29,988	553	41.0	3,747	5.0
August	25,662	767	35.5	3,295	4.4
September	23,474	0	32.6	3,305	4.6

5.4.3 Cogeneration Cycle Analysis

The situation at Grissom is similar to that at Griffiss in that a new high-pressure stoker-fired boiler and turbine generator would be required for a cogeneration plant. A boiler output equal to the combined capacity of the boilers in the present heating plant was chosen for analysis. The cycle flow diagram is shown in Fig. 5.5. Steam conditions at the turbine inlet are 1500 psia and 840°F, heating steam is extracted at 140 psia, and the condenser pressure is 5 psia.

The boiler steam flow would vary from 110,000 to 158,000 lb/h and the heating steam extraction flow from 0 to 96,000 lb/h. The variation of power output with heat load, shown in Fig. 5.6, is from 12.4 MW(e) at

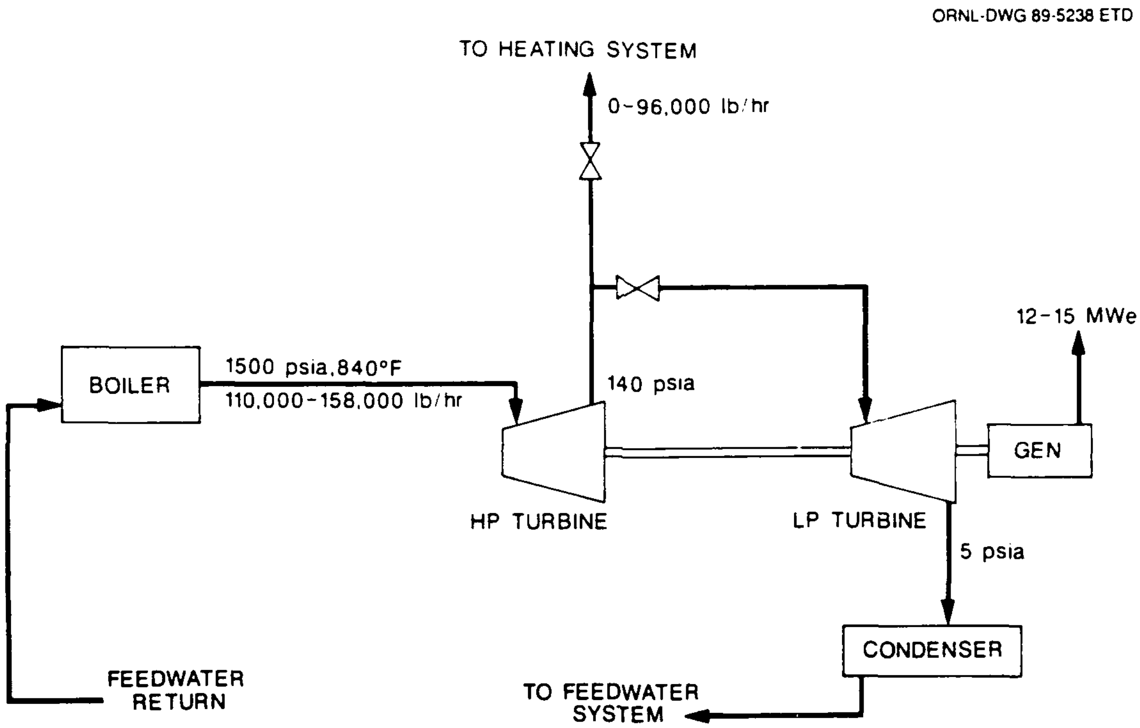

Fig. 5.5. Cogeneration cycle flow diagram for Grissom AFB.

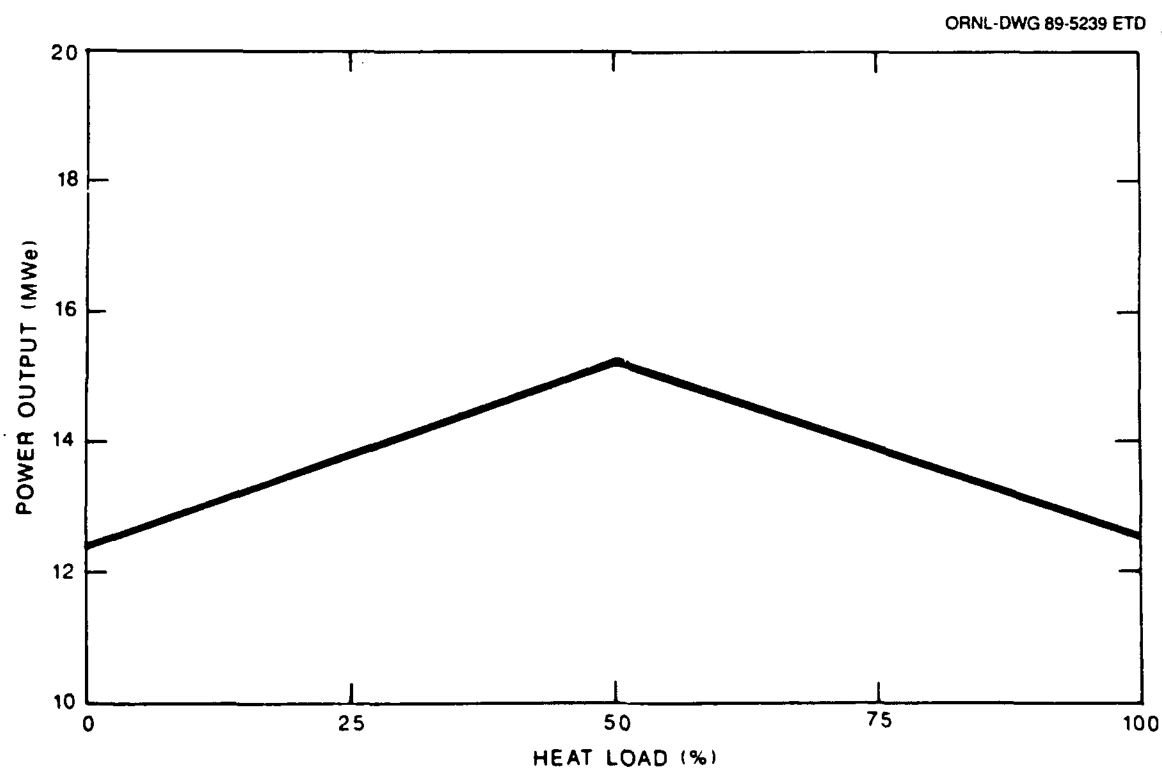

Fig. 5.6. Power output vs heat load for cogeneration cycle applied to Grissom AFB.

no heat load to 15.2 MW(e) at 50% heat load, and down to 12.5 MW(e) at full heat load. The average heat output (assuming 1050 Btu/lb steam) and power output are shown for each month of the year in Table 5.6. The annual capacity factors are 0.52, 0.87, and 0.89 for heat, electricity, and the boiler, respectively.

Table 5.6. Monthly average heat and power output for cogeneration cycle applied to Grissom AFB

Month	Average heat output (MBtu/h)	Average power output [MW(e)]
October	36.9	14.5
November	66.1	14.4
December	100.8	12.5
January	91.5	13.0
February	83.3	13.4
March	85.0	13.3
April	54.4	15.0
May	31.2	14.1
June	25.9	13.8
July	33.5	14.3
August	29.0	14.0
September	25.7	13.8

6. DESCRIPTION OF ECONOMIC ANALYSIS

The economic analysis methodology used for the coal-fired cogeneration systems differed somewhat from the methodology described previously in Chap. 5 of Ref. 3 for the coal-fired heating systems. In the cogeneration analysis described in this report, only one coal combustion technology (either circulating FBC or field-erected stoker) was examined for each Air Force base. This resulted in a much smaller number of individual cases than for the previous heating plant study, where up to 12 different coal technology options were included for each Air Force base. However, the economic analysis of each cogeneration case was slightly more complicated because of (1) the extra costs associated with the turbine generator and electrical equipment and (2) the annual revenue resulting from the sale of electric power.

6.1 COST ESTIMATES FOR BASES CURRENTLY BURNING OIL/GAS

The coal-fired boilers selected for the proposed cogeneration systems at Hill, Kelly, McGuire, and Plattsburgh AFBs are circulating FBC units that produce 250,000 lb/h of 1500-psia superheated steam. Equations for estimating the capital costs and the annual O&M costs as a function of size of coal-fired circulating FBC systems (with low-pressure, heating-only boilers) were developed previously at ORNL.[1,3] O&M cost equations were also developed in the previous study for the continued firing of oil/gas at existing heating plants. Those oil/gas heating plant cost equations were used without modification in this cogeneration analysis, but the previous coal-fired circulating FBC cost estimates required alterations to account for additional costs associated with the high-pressure boiler components, the turbine generator, and the electrical equipment.

Circulating FBC capital costs. Capital cost information that is publicly available for coal-fired circulating FBC cogeneration systems is limited because costs are usually considered confidential. A simple approach was chosen for appraising the capital costs of the proposed circulating FBC cogeneration plants. A single lump-sum capital cost was estimated for the entire cogeneration plant rather than estimating the costs of the numerous individual components that make up the plant. There was no reason to scale the capital cost estimate over a range of sizes because all of the proposed systems are almost the same capacity [250,000 lb/h, ~25 MW(e)]. Based on the small amount of cost information available from sources such as conference proceedings[6,7] and personal communications with vendors and plant owners, a capital cost of $45 million (1988 dollars) was estimated for the proposed coal-fired circulating FBC cogeneration plants.

The capital estimate includes costs for (1) a new boiler house, (2) a high-pressure circulating FBC boiler with superheat, (3) a solids-storage/-handling system for coal and limestone, (4) an ash-handling system with a baghouse for particulate control, (5) an extraction steam turbine with a condenser, and (6) a generator and associated electrical equipment. No additional capital equipment is required for SO_2 and NO_x control because these emissions are inherently low in circulating FBC boilers when limestone sorbent is injected into the boiler. It is estimated that the electric generating components (items 5 and 6 above) account for about one-third (~$15 million) of the total capital cost.

Circulating FBC O&M costs. The annual O&M costs for the proposed circulating FBC cogeneration plants were estimated by using a slightly modified version of the equations developed previously for circulating FBC heating plants.[1,3] Most of those previous O&M cost relationships could be used without modification for the cogeneration plants, but some cogeneration costs will be higher because of the turbine generator and electrical equipment. The two O&M categories assumed to be affected are (1) operating labor was increased ~27%, and (2) repair labor and materials were increased ~20%. It was also assumed that a cogeneration boiler would be slightly more efficient than a heating boiler because the cogeneration boiler experiences a relatively steady load. An average boiler efficiency of 83% was used, rather than the 81% efficiency used for circulating FBC boilers in the previous heating plant studies.[1,3]

About 20 input parameters are required for the O&M cost relationships. The current fuel and electric price assumptions for the four candidate Air Force bases have already been presented in Table 3.1. These current prices may escalate with time as is described later in Sect. 6.3.1. The selection of boiler size and the capacity factor assumptions for each Air Force base were discussed in Chap. 4. The values used for coal properties (ash content, sulfur content, higher heating value) can be found in the LCC summary sheets in the Appendix. Because of a lack of better information, the other input parameters listed below were assumed to remain constant from site to site:

labor rate	$36,400/year
limestone price	$20.80/ton
limestone inert fraction	5% by weight
ash disposal price	$7.80/ton

Limestone addition is required for sulfur capture at all four candidate bases because the proposed circulating FBC cogeneration plants must meet federal environmental regulations for boilers with fuel inputs >100 MBtu/h.

6.2 COST ESTIMATES FOR BASES CURRENTLY BURNING COAL

The existing coal-fired boilers at Wright-Patterson, Griffiss, and Grissom AFBs are stoker units. The design goal for the proposed cogeneration plants at these three candidate bases was to reuse as much of the existing coal-firing equipment as possible. It was assumed that the solids-storage/-handling components at all three bases could be reused, which limited the combustion technology to stoker coal and also limited the maximum size of the cogeneration systems to the size of the existing coal feeding systems. It was also assumed that any existing particulate and/or SO_2 removal components could be reused and that no additional emission control equipment would be required.

Stoker capital costs. At Griffiss and Grissom AFBs, the items that must be procured are (1) a new boiler house, (2) a new high-pressure (1500-psia) stoker boiler with superheat, (3) an extraction steam turbine with a condenser, and (4) a generator and associated electrical equipment. At Wright-Patterson AFB, a unique situation exists because the existing stoker boilers are already capable of producing relatively high-pressure (465-psia) steam. The electric generating components (items 3 and 4 above) are all that must be acquired at Wright-Patterson.

The capital costs of the proposed stoker cogeneration plants were first estimated for a nominal capacity of 250,000 lb/h, 25 MW(e), and then scaled to other sizes as necessary. The total capital costs were split into two categories: (1) the 250,000-lb/h stoker boiler components were estimated to cost about \$15 million and (2) the 25-MW(e) electrical generating components were estimated to cost also about \$15 million. The stoker boiler costs are based on the previous work at ORNL,[1,3] and the electrical equipment costs are discussed in Sect. 6.1. Both capital categories apply to Griffiss and Grissom AFBs, but only the electrical category applies to Wright-Patterson AFB. A simple capital cost equation was derived for Griffiss and Grissom AFBs by using a scaling factor of 0.7:

$$\text{Capital} = \$30\text{M}\ [(\text{steam flow rate})/(250{,}000\ \text{lb/h})]^{0.7}\ .$$

A similar equation was derived for Wright-Patterson AFB:

$$\text{Capital} = \$15\text{M}\ \{(\text{electric output})/[25\ \text{MW(e)}]\}^{0.7}\ .$$

Stoker O&M costs. The annual O&M costs for the proposed stoker cogeneration plants will be similar to the O&M costs for the existing stoker heating plants at the three candidate Air Force bases. The O&M costs were estimated for the existing stoker heating plants by using the equations developed previously at ORNL.[1,3] The O&M costs were estimated for the proposed stoker cogeneration plants by modifying those equations to include additional O&M costs for the turbine generator and electrical equipment. It was assumed that two O&M categories would be affected: (1) operating labor was increased ~29%, and (2) repair labor and materials were increased ~20%. It was also assumed that a cogeneration boiler would be more efficient than a heating boiler because the cogeneration boiler experiences a relatively steady load. An average boiler efficiency of 82% was used rather than the 80% efficiency used for stoker boilers in the previous heating plant studies,[1,3] and for sites that require flue gas desulfurization, an efficiency of 80% was used rather than 78% (2% loss from SO_2 control system).

The input parameters for the stoker O&M cost relationships are similar to the O&M input parameters discussed in Sect. 6.1, with a major exception that relates to SO_2 control. The existing stoker boilers at Wright-Patterson and Grissom AFBs do not currently use any special equipment for sulfur capture, and it was assumed that new stoker boilers of equal size could be operated without any SO_2 control. However, the existing stoker boilers at Griffiss AFB use lime scrubbers for flue gas desulfurization. The following input parameters were used to estimate the cost of continued operation of the lime scrubbers at Griffiss AFB:

lime price	$41.60/ton
lime inert fraction	5% by weight

The other site-specific input parameters for the three candidate Air Force bases currently burning coal were presented in Table 3.2 and Chap. 5.

6.3 LCC ANALYSIS

6.3.1 Economic Assumptions

The LCC analysis included two financing scenarios: (1) one for Air Force ownership and operation of the coal-fired cogeneration equipment and (2) one for private ownership and operation. The Air Force-financing scenario is based on the assumptions that MCP funding will be used to finance a cogeneration project and that all electricity will be sold to the local utility. Air Force financing is a hypothetical scenario that was analyzed only to provide a basis for economic comparison with the previous heating plant study.[3] It is not anticipated that the Air Force will use MCP funding for the cogeneration plants examined in this report because of budgetary constraints and because the Air Force is not allowed to sell electricity to local utilities.

The private-financing scenario is based on the assumption that the Air Force will enter into a long-term contract (or a series of 1-year contracts with a long-term termination liability clause) with a private company to construct, operate, and maintain the coal-fired cogeneration equipment. The contract will require the Air Force to purchase a fixed annual quantity of steam from the private company for a fixed annual price. The private company will sell all electricity to the local utility.

Table 6.1 summarizes the important economic assumptions used in the LCC analysis for both the Air Force- and private-financing scenarios. The assumptions are identical to those used in the previous heating plant study.[3] Cogeneration projects are assumed to start at the beginning of 1990 with a 1-year construction period. Coal-firing begins in 1991 and continues for 30 years through the end of 2020. Some of the other parameters in Table 6.1 are defined and explained in more detail below.

Table 6.1. Economic assumptions used in LCC analysis

Parameter	Air Force financing	Private financing
Project start year, start of construction	1990	1990
Construction period, years	1	1
Economic life of project, years	30	30
Salvage value at end of economic life, $	0	0
Time-dependent curve for maintenance costs	U-shaped	U-shaped
Escalation and discounting base year	1988	1988
General inflation rate, %	0	0
Energy real escalation rates	Three levels	Three levels
Real discount rate, %	10 and 7	10 and 7
Equity, % of capital investment	Not applicable	100
Before-tax real return on investment, %	Not applicable	17 and 14
Amount of working capital, month	Not applicable	2

Time-dependent curve for maintenance costs. Maintenance costs are treated in a special way. The annual maintenance costs generated by the cost-estimating relationships are adjusted by the time-dependent multiplier shown in Fig. 6.1. The U-shaped curve accounts for extra costs that occur because of infant failures during the first 3 years of cogeneration plant operation, and old-age failures during the last 8 years.

General inflation rate. The general inflation rate was assumed to be zero in this study. The effect of this assumption is that all future cash values will be in constant dollars, as is required by federal guidelines.[8]

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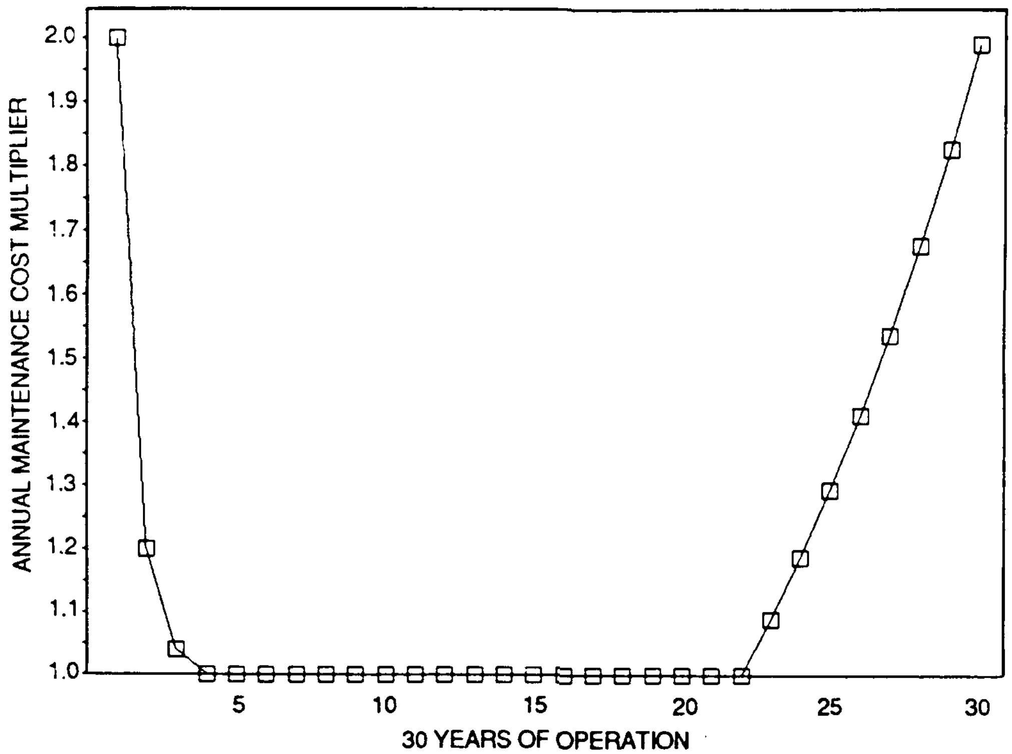

Fig. 6.1. Time-dependent multiplier applied to annual maintenance costs.

Energy escalation rates. Three levels of energy escalation have been examined: high, medium, and zero. The high energy escalation case was derived from a DOD memo that gives guidelines for energy-dependent economic analyses.[4] The DOD escalators are based directly on a 1986 report published by the Energy Information Administration (EIA) of the U.S. Department of Energy.[9] Energy escalation projections are tabulated in the DOD memo and the 1986 EIA report for distillate oil, residual oil, natural gas, coal, and electricity, for both commercial and industrial sectors, in ten different regions of the United States. For the LCC analysis in this report, it was assumed that the industrial energy escalation rates, averaged over all ten regions of the United States, are applicable. Also, distillate and residual oils were assumed to escalate at the same rate (equal to an average of the escalation rates for distillate and residual oils).

The 1986 study by the EIA includes projections only to the year 2000. The DOD escalation tables were extended to the year 2017 by assuming that the 1986 EIA escalation projections for the years 1996–2000 (escalation rates for each energy category are constant during this 5-year period) would remain constant through the year 2017. For the LCC analysis in this report, the 30-year economic life ends in the year 2020, therefore the same escalation rates were assumed to apply all the way to the year 2020. The rates for the high escalation case just described are shown at the top of Table 6.2. For this high escalation case, gas and oil prices escalate at rather high rates relative to the price of coal. Even though the high escalation case is based on projections that are now somewhat outdated, they are included here to provide a basis for comparison with the previous heating plant study.[3]

Table 6.2. Energy escalation levels

Energy category	Real escalation rate (%/year)			
	1988–1990	1990–1995	1995–2000	2000 and beyond
	High escalation case			
Gas	3.89	8.87	5.77	5.77
Oil	4.86	7.87	4.16	4.16
Coal	1.16	2.31	1.19	1.19
Electric	−1.72	−1.65	0.85	0.85
	Medium escalation case			
Gas	2.28	4.70	5.49	2.75
Oil	0.17	4.16	5.55	2.77
Coal	1.46	1.76	1.61	0.81
Electric	−1.18	−0.61	1.05	0.52
	Zero escalation case			
Gas	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0
Electric	0.0	0.0	0.0	0.0

The medium energy escalation case was developed from the 1987 version of the EIA report.[10] Because the updated 1987 EIA report also does not include any escalation projections beyond the year 2000, an author of the report was contacted and asked to recommend the best assumptions during that time period. The opinion received was that the forces causing high oil and gas price escalation during the 1995–2000 period will weaken significantly in years beyond 2000. To simulate reduced pressure on energy prices for years beyond 2000, it was assumed that each energy category escalates at half the projected rate for the 1995–2000 period. The precise values used for this medium escalation case are given in Table 6.2. The medium escalators lie approximately midway between the high escalators and the third case of zero escalation of energy prices.

Discount rate. Federal guidelines specify that a real discount rate of 10% should be used for the evaluation of projects that are not primarily for energy conservation.[8] For most of this study, an actual discount rate of 10% was used, which is equivalent to a real discount rate of 10% because of the assumption of zero general inflation. A 7% discount rate was also examined to determine the sensitivity of the results to the discount rate.

Before-tax return on investment. A representative ROI is needed for the evaluation of privately financed projects. For most of this study, a before-tax ROI of 17% was used. This before-tax ROI is not pure profit because it was assumed that the private contractor will have to use part of it to pay taxes and insurance. Based on the assumptions of (1) 2% local property tax and insurance, (2) 15-year sum-of-the-years digits depreciation, and (3) 34% federal income tax, a 17% before-tax ROI translates to an after-tax ROI of ~12%. A before-tax ROI of 14% was also examined to determine the sensitivity of the results to the ROI.

Amount of working capital. It was assumed that a private contractor will incur O&M costs (including fuel costs) an average of 2 months before reimbursement for them. This 2-month investment is called working capital. In the private-financing calculations, a return on working capital (ROWC) is calculated at a rate equal to the ROI.

6.3.2 Present Worth Calculations

LCCs were calculated with the aid of present worth factors (PWFs). PWFs are used to translate future costs or revenues that occur at different times into their cash equivalents at the present time. PWFs account for both the opportunity cost of money (discounting) and changes in the real prices of energy (escalation).

The LCCs of the proposed cogeneration plants were calculated from the viewpoint that the steam/HTHW output from a cogeneration plant would displace an equal amount of steam/HTHW output from an existing Air Force heating plant. The LCCs in this study are therefore defined as the cost of generating steam. All of the electric power that is produced by a cogeneration plant is treated as a revenue that reduces the cost of generating steam. The following equation was used to calculate life-cycle costs:

$$\begin{aligned} LCC = \; & (\text{Total Capital})\ PWF_{Cap} + (\text{Annual O\&M})\ PWF_{O\&M} \\ & + (\text{Annual Maintenance})\ PWF_{Maint} + (\text{Annual Fuel})\ PWF_{Fuel} \\ & - (\text{Annual Electric})\ PWF_{Elec}. \end{aligned}$$

The capital and annual cost estimates that were used in the above LCC equation are discussed in Sects. 6.1 and 6.2. The PWFs that were applied to the capital and annual costs are listed in Table 6.3 for a 10% discount rate and a 17% before-tax ROI. Table 6.3 includes six sets of PWFs for the two financing scenarios and the three energy escalation levels.

6.3.3 Definitions of Figures-of-Merit

A personal computer was used to produce an LCC summary sheet like the example shown in Table 6.4 for each set of input parameters. The LCC summary sheet is split into three sections: the top section lists the input parameters, the middle section summarizes the capital and O&M cost estimates, and the bottom section shows the results of the LCC analysis. The bottom section includes the results for both the Air Force- and private-financing scenarios and all three energy escalation levels. In the LCC results section, the costs of a proposed coal-fired cogeneration plant are compared with the costs of the existing heating

Table 6.3. PWFs for 10% discount rate and 17% ROI

Cost	PWFs High energy escalation	Medium energy escalation	Zero energy escalation
Air Force financing			
Capital	0.8264	0.8264	0.8264
Uniform O&M	7.7908	7.7908	7.7908
U-shaped maintenance	8.9416	8.9416	8.9416
Natural gas	17.5591	12.4991	7.7908
Oil	15.2264	11.7497	7.7908
Coal	9.3426	9.1836	7.7908
Electricity	7.3423	7.6222	7.7908
Private financing			
Capital	1.3365	1.3365	1.3365
Uniform O&M (includes ROWC)	8.0116	8.0116	8.0116
U-shaped maintenance (includes ROWC)	9.4946	9.4946	9.4946
Natural gas			
Oil			
Coal (includes ROWC)	9.2673	9.1531	8.0116
Electricity	7.2511	7.5217	7.7908

plant through the use of three different figures-of-merit: (1) LCC, (2) benefit/cost rati and (3) discounted payback period. These figures-of-merit are defined and discussed in this section.

LCC. The LCC of a project is the summation of the discounted annual expenditures and revenues over the 30-year economic life of the project. The LCCs shown in Table 6.4 come from the LCC equation in Sect. 6.3.2. LCCs are calculated for the proposed coal-fired cogeneration system, as well as the portion of the existing heating plant that would be displaced. Because LCCs that have been escalated and discounted over a 30-year period can result in dollar amounts that are difficult to comprehend in absolute terms, they are most useful for relative comparisons between projects.

Benefit/cost ratio. The term "benefit" is used in this report to refer to cost avoidance (i.e., avoiding the cost of continued operation

Table 6.4. Example LCC summary sheet for Hill AFB

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1258.1	1050.0
Max. output capacity, MBtu/h =	314.5	105.0
Capacity factor =	0.886	0.618

Electric System	
Specific output, kWh/klb =	104.0
Max. output capacity, kW =	26,000
Capacity factor =	0.850
Purchase price, $/kWh =	0.0520
Sales price, $/kWh =	0.0520

ROM Coal Properties	
Ash fraction =	0.080
Sulfur fraction =	0.006
HHV, Btu/lb =	11,650
Price, $/MBtu =	1.20

Current Primary Fuel	
Gas price, $/MBtu =	2.81
#6 Oil price, $/MBtu =	0.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	0.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	0.800	2.81	0.0	1996.6	248.8	591.1	0.0
#6 Oil boiler	0.800	0.00	0.0	0.0	0.0	0.0	0.0
CFB cogen	0.830	1.20	45000.0	3529.4	783.0	1884.5	10067.0

Coal use, ton/yr = 126,229 Limestone use, ton/yr = 4,983

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
		High Energy Escalation			
Gas boiler	41,889	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	17,932	2.336	12.9	42,384	0.988
		Medium Energy Escalation			
Gas boiler	31,786	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	14,552	2.184	13.4	39,257	0.810
		Zero Energy Escalation			
Gas boiler	22,385	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	7,939	2.820	12.9	32,519	0.688

of an existing system) rather than cost savings (i.e., the difference between the cost of an existing system and the cost of a new system). The benefit/cost ratio is therefore defined as the LCC of the portion of the existing heating plant that would be displaced, divided by the LCC of the new coal-fired cogeneration system. In the example LCC summary sheet in Table 6.4, the numerators of the benefit/cost ratios are equal to the LCCs of the natural gas boiler, and the denominators are equal to the LCCs of the circulating fluidized-bed (CFB) cogeneration system.

The benefit/cost ratio is the primary figure-of-merit used in this report to interpret the economic results. In general, the use of benefit/cost ratios is not recommended when budget constraints are important. However, the results in this report are not intended to be used for allocating a fixed budget between competing projects; the purpose is instead to provide guidance for planning Air Force budget requests and/or planning privatized projects. The use of benefit/cost ratios ensures that cost-effective projects are not overlooked just because they are capital intensive.

Two questions can be answered by examining the benefit/cost ratios: (1) Which air base has the greatest potential for economical implementation of cogeneration? (2) Will cogeneration be more economical than the existing heating plant? The first question involves a relative comparison between two or more benefit/cost ratios, while the second question depends only on the absolute magnitude of the benefit/cost ratios. In the example in Table 6.4, an Air Force-financed cogeneration plant will be more economical than the existing heating plant because the benefit/cost ratio is >1.0 for all three energy escalation projects.

<u>Discounted payback period</u>. This parameter is defined as the time period (measured from the beginning of construction) required for the cumulative savings from a project to pay back the initial investment and other cumulative costs of the project, taking into account the time value of money. During the first few years of a coal-fired cogeneration project, the cumulative discounted costs of the cogeneration system will tend to be greater than the cumulative discounted costs of the existing

heating plant because of the high capital costs of the coal-fired cogeneration equipment. However, the cumulative costs of the cogeneration system will tend to increase with time more slowly than the cumulative costs of the heating plant because of the revenues generated by the sale of electricity. The discounted payback period is defined as the point in time where the cumulative discounted costs of the cogeneration system fall below the cumulative discounted costs of the existing heating plant.

The discounted payback period is used in this report only as a secondary figure-of-merit because (1) the discounted payback period has no meaning in the private-financing scenarios where the Air Force does not invest any of its own capital, (2) the discounted payback period will sometimes be undefined because it can be greater than the economic life of the project, and (3) an economic evaluation using discounted payback periods will sometimes be misleading because they completely ignore the economic consequences beyond the payback period.

7. RESULTS OF ECONOMIC ANALYSIS

The results of the economic analysis of cogeneration plants at the seven Air Force bases are presented in this section. The findings are given primarily in terms of the benefit/cost ratio (as defined in Sect. 6.3.3). The effects on the benefit/cost ratio of energy escalation assumptions, method of financing, discount rate, and ROI are discussed. More specific details about the results of the economic analysis can be found in the LCC summary sheets in the Appendix.

7.1 BASES CURRENTLY BURNING OIL/GAS

The benefit/cost ratios for the four bases presently firing oil or gas are listed in Table 7.1 in descending order of the benefit/cost ratio: Hill, McGuire, Plattsburgh, and Kelly. With Air Force financing, the benefit exceeds cost for all four bases with high energy escalation and for three bases for medium and zero energy escalation. The benefit/cost ratio for Air Force financing is the greatest at zero escalation, decreases with medium escalation, but increases again at high escalation. This is a result of the differing escalation rates for oil, gas, and coal and the slight deescalation projected for electric power rates. The results of the analysis for Air Force financing provide only a basis for economic comparison, since it is not anticipated that cogeneration plants would be built with Air Force financing.

Table 7.1. Economic results for bases currently firing oil/gas

Base	Benefit/cost ratio					
	10% Air Force financing with 3 assumptions for energy escalation			17% Private financing with 3 assumptions for energy escalation		
	High	Medium	Zero	High	Medium	Zero
Hill	2.336	2.184	2.820	0.988	0.810	0.688
McGuire	1.536	1.381	1.675	0.787	0.645	0.562
Plattsburgh	1.352	1.252	1.401	0.757	0.654	0.579
Kelly	1.099	0.942	0.970	0.647	0.525	0.447

With private financing, the benefit is less than the cost for all the bases. The benefit/cost ratio decreases with decreasing energy escalation rates for the case of private financing. The great difference between the benefit/cost ratios for Air Force and private financing comes about from the dominant effect of the large capital investment cost on the economics.

7.1.1 Hill Air Force Base

The benefit/cost ratio for Hill AFB is large with Air Force financing for all three levels of energy escalation assumptions. With private financing, the benefit is less than the cost for all levels of escalation. The major factor influencing the economics here is the low price of coal coupled with the electric power rate. The coal use with a cogeneration plant would be ~126,200 tons/year.

7.1.2 McGuire Air Force Base

The benefit/cost ratio for McGuire AFB is reasonably large with Air Force financing for all three levels of energy escalation assumptions. With private financing, the benefit is less than the cost for all levels of escalation. The coal use with a cogeneration plant would be ~106,900 tons/year.

7.1.3 Plattsburgh Air Force Base

The benefit/cost ratio for Plattsburgh AFB is fairly large with Air Force financing for all levels of energy escalation. The benefit is less than the cost for all levels of escalation with private financing. The coal use with a cogeneration plant would be ~108,600 tons/year.

7.1.4 Kelly Air Force Base

The benefit/cost ratio for Kelly AFB is just slightly >1 for high energy escalation and <1 for medium and zero escalation with Air Force financing. The benefit is less than the cost for all levels of escalation with private financing. The coal use with a cogeneration plant would be ~122,800 tons/year.

7.2 BASES CURRENTLY BURNING COAL

The benefit/cost ratios for cogeneration plants at the three bases already firing coal are listed in Table 7.2 in descending order of the benefit/cost ratio: Griffiss, Grissom, and Wright-Patterson. With Air Force financing, the benefit/cost ratio is the highest at zero energy escalation and decreases with medium and high escalation. Only one base has a benefit greater than the cost. With private financing, the same base has a benefit greater than the cost, but only for zero energy escalation. The decrease in benefit/cost ratio with higher escalation results from the fact that coal prices are projected to increase, while electric rates are projected to decrease slightly.

Table 7.2. Economic results for bases currently firing coal

Base	Benefit/cost ratio					
	10% Air Force financing with 3 assumptions for energy escalation			17% Private financing with 3 assumptions for energy escalation		
	High	Medium	Zero	High	Medium	Zero
Griffiss	1.713	2.553	*a*	0.728	0.831	1.218
Grissom	0.726	0.778	0.934	0.500	0.520	0.562
Wright-Patterson	0.703	0.732	0.832	0.615	0.632	0.676

[a]The LCC of generating heating steam in the cogeneration plant is <0 because the revenue from electricity is greater than the capital, O&M, and fuel costs. The benefit/cost ratio is therefore undefined because the denominator is negative.

7.2.1 Griffiss Air Force Base

With Air Force financing, the benefit/cost ratio is fairly large for Griffiss AFB. The LCC of the cogeneration plant is <0 for the assumption of zero energy escalation. With private financing, the benefit is less than cost except for zero escalation. The incremental coal use above the quantity used now would be ~109,300 tons/year with a cogeneration plant.

7.2.2 Grissom Air Force Base

At Grissom AFB, the benefit is less than the cost for a cogeneration plant with either Air Force or private financing for all the assumed levels of energy escalation. The electric power rate is too low to offset the capital cost of a new high-pressure boiler and turbine generator.

7.2.3 Wright-Patterson Air Force Base

At Wright-Patterson AFB, the benefit is less than the cost for cogeneration with either Air Force or private financing for all three levels assumed for energy escalation. Even though only a turbine generator would have to be added, the electric power rate is too low to offset the capital cost.

7.3 EFFECT OF LOWER DISCOUNT RATE AND RETURN ON INVESTMENT

The effects of a lower discount rate and a lower return on investment were examined. A discount rate of 7% was assumed compared with 10% for the baseline calculations, and an ROI of 14% was assumed compared with 17% for the baseline assumption. The lower discount rate of 7% affects the LCC calculations for both Air Force and private financing, but the lower ROI of 14% affects the calculations only for private financing. The benefit/cost ratios for these lower rates are shown in Table 7.3 for each of the seven bases studied. In every case, the benefit/cost ratio is larger for the lower values of discount rate and ROI. For Air Force financing, the benefit/cost ratios increased by ~40 to 70%. With private financing, the benefit/cost ratios increased by ~30 to 50%. For Kelly AFB, the benefit becomes larger than the cost for all levels of energy escalation with Air Force financing. The benefit is calculated to be greater than the cost for Hill AFB with private financing for all levels of energy escalation.

Table 7.3. Effect of lower discount rate and ROI

Base	Benefit/cost ratio					
	7% Air Force financing with 3 assumptions for energy escalation			14% Private financing with 3 assumptions for energy escalation		
	High	Medium	Zero	High	Medium	Zero
Hill	5.100	6.046	*a*	1.428	1.156	1.013
McGuire	2.535	2.440	5.762	1.081	0.870	0.780
Plattsburgh	1.995	1.940	2.840	0.990	0.857	0.768
Kelly	1.590	1.372	1.669	0.853	0.674	0.577
Griffiss	3.174	8.621	*a*	0.958	1.154	2.165
Grissom	0.865	0.944	1.214	0.579	0.608	0.673
Wright-Patterson	0.736	0.769	0.892	0.654	0.673	0.727

[a]The LCC of generating heating steam in the cogeneration plant is <0 because the revenue from electricity is greater than the capital, O&M, and fuel costs. The benefit/cost ratio is therefore undefined because the denominator is negative.

7.4 CREDIT FOR REPLACEMENT BOILERS AND BACKUP ELECTRIC POWER

The boilers at Plattsburgh AFB are in rather poor condition and need to be replaced soon. Also, at Plattsburgh, Hill, and Wright-Patterson the backup electric generating capacity on-base is less than is needed to perform their mission if all outside power sources were to be lost. Alternative cases were analyzed for these bases in which capital charges for replacement oil-fired boilers and emergency diesel generators at Plattsburgh and for emergency diesel generators at Hill and Wright-Patterson were included in the costs of the existing systems. The benefit/cost ratios for these assumptions are shown in Table 7.4. The benefit becomes greater than the cost for Hill for all three levels of energy escalation with private financing when credit is taken for backup electric power generation.

Table 7.4. Effect of replacement boiler and backup electric power credits

Base	Benefit/cost ratio					
	10% Air Force financing with 3 assumptions for energy escalation			17% Private financing with 3 assumptions for energy escalation		
	High	Medium	Zero	High	Medium	Zero
Hill	3.027	3.036	4.381	1.281	1.125	1.070
Plattsburgh	1.577	1.510	1.798	0.884	0.789	0.743
Wright-Patterson	0.952	0.995	1.165	0.833	0.859	0.947

7.5 DISCOUNTED PAYBACK PERIOD

The discounted payback period was calculated for Air Force financing of projects for both 10 and 7% discount rates, as shown in Table 7.5. At the 10% discount rate, the payback periods ranged from about 9 to 20 years for the top four bases. These were reduced to ~8 to 14 years for the 7% discount rate.

Table 7.5. Discounted payback periods for Air Force financing

Base	Discounted payback periods (years)					
	10% Discount rate with 3 assumptions for energy escalation			7% Discount rate with 3 assumptions for energy escalation		
	High	Medium	Zero	High	Medium	Zero
Hill	12.9	13.4	12.9	10.7	11.0	10.6
McGuire	17.0	18.2	16.3	13.4	13.7	12.4
Plattsburgh	17.8	19.7	17.4	13.7	14.4	12.9
Kelly	25.8	>31	>31	17.8	19.5	17.4
Griffiss	13.5	11.2	8.5	10.9	9.5	7.6
Grissom	>31	>31	>31	>31	>31	19.1
Wright-Patterson	>31	>31	>31	>31	>31	>31

7.6 SUMMARY OF RESULTS

In general, Air Force financing of cogeneration plants appears more economical than private financing, but it is not anticipated that cogeneration plants would be built with Air Force financing. Hill, McGuire, and Plattsburgh are the most promising candidates for Air Force-financed projects. The economics look promising for Griffiss, but installing a high-pressure boiler and turbine generator for cogeneration would place their existing coal-fired heating boilers, which are quite new, on standby. Private financing would be economical at Hill if credit is allowed for on-base backup electric power, or if private financing were provided at a 14% ROI.

8. CONCLUSIONS AND RECOMMENDATIONS

The results of the economic analysis of coal-fired cogeneration plants at four Air Force bases that currently use oil or gas as heating fuel and three bases that use coal lead to the following conclusions:

1. Even though it is not anticipated that cogeneration plants would be built with Air Force financing, cogeneration projects appear to be economically attractive with Air Force financing at the following bases:
   - Hill AFB,
   - McGuire AFB, and
   - Plattsburgh AFB.
2. A cogeneration project at Griffiss AFB appears to be economically attractive with Air Force financing but would place their recently installed coal-fired heating boilers on standby.
3. Private financing of cogeneration plants does not appear to be economically attractive at any of the bases studied except at Hill, where private financing would be economical only if credit is allowed for on-base emergency generators, or if a return on investment of 14% were acceptable.
4. The three most promising candidate bases for cogeneration plants would consume the following approximate quantities of coal:
   - Hill AFB – 126,000 tons/year,
   - McGuire AFB – 106,000 tons/year, and
   - Plattsburgh AFB – 108,000 tons/year.

It is recommended that feasibility studies of coal-fired cogeneration plants be initiated for each of the three leading candidate bases identified above. The studies should be done in sufficient detail to ensure that all site-specific factors are properly taken into account in reaching the final conclusions.

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Appendix

LIFE-CYCLE COST SUMMARY SHEETS

The life-cycle cost (LCC) calculations were performed on a personal computer using spreadsheet software. For each set of input parameters, the spreadsheet software produced a single-page summary sheet. The LCC summary sheet is split into three sections: the top section lists the input parameters, the middle section summarizes the capital and O&M cost estimates, and the bottom section shows the results of the LCC analysis. The bottom section includes the results for both the Air Force- and private-financing scenarios, as well as all three energy escalation levels. This appendix contains the LCC summary sheets that document all of the economic results discussed in Chap. 7. For each base, there are two or three summary sheets arranged in the following order: (1) base case, (2) effect of low cost of money (discount rate and return on investment), and (3) effect of capital credit for replacement boilers or backup electric power (only for Hill, Plattsburgh, and Wright-Patterson AFBs):

Base	Number of summary sheets	Page
Hill	3	62
McGuire	2	65
Plattsburgh	3	67
Kelly	2	70
Griffiss	2	72
Grissom	2	74
Wright-Patterson	3	76

HILL AFB: 250 klb/h COGENERATION

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1258.1	1050.0
Max. output capacity, MBtu/h =	314.5	105.0
Capacity factor =	.886	.618

Electric System	
Specific output, kWh/klb =	104.0
Max. output capacity, kW =	26,000
Capacity factor =	.850
Purchase price, $/kWh =	.0520
Sales price, $/kWh =	.0520

ROM Coal Properties	
Ash fraction =	.080
Sulfur fraction =	.006
HHV, Btu/lb =	11,650
Price, $/MBtu =	1.20

Current Primary Fuel	
Gas price, $/MBtu =	2.81
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	2.81	0.	1996.6	248.8	591.1	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
CFB cogen	.830	1.20	45000.	3529.4	783.0	1884.5	10067.0
Coal use, ton/yr = 126,229				Limestone use, ton/yr = 4,983			

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
		High Energy Escalation			
Gas boiler	41,889	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	17,932	2.336	12.9	42,384	.988
		Medium Energy Escalation			
Gas boiler	31,786	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	14,552	2.184	13.4	39,257	.810
		Zero Energy Escalation			
Gas boiler	22,385	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	7,939	2.820	12.9	32,519	.688

HILL AFB: 250 klb/h COGENERATION, LOW COST OF MONEY

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1258.1	1050.0
Max. output capacity, MBtu/h =	314.5	105.0
Capacity factor =	.886	.618

Electric System	
Specific output, kWh/klb =	104.0
Max. output capacity, kW =	26,000
Capacity factor =	.850
Purchase price, $/kWh =	.0520
Sales price, $/kWh =	.0520

ROM Coal Properties	
Ash fraction =	.080
Sulfur fraction =	.006
HHV, Btu/lb =	11,650
Price, $/MBtu =	1.20

Current Primary Fuel	
Gas price, $/MBtu =	2.81
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	7.00
Private before-tax ROI, % =	14.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	2.81	0.	1996.6	248.8	591.1	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
CFB cogen	.830	1.20	45000.	3529.4	783.0	1884.5	10067.0

Coal use, ton/yr = 126,229 Limestone use, ton/yr = 4,983

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
			High Energy Escalation		
Gas boiler	63,709	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	12,491	5.100	10.7	44,608	1.428
			Medium Energy Escalation		
Gas boiler	46,346	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	7,666	6.046	11.0	40,094	1.156
			Zero Energy Escalation		
Gas boiler	31,126	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	-1,439	-21.624	10.6	30,717	1.013

HILL AFB: 250 klb/h COGENERATION, 15.0 M$ CAPITAL CREDIT

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1258.1	1050.0
Max. output capacity, MBtu/h =	314.5	105.0
Capacity factor =	.886	.618

Electric System	
Specific output, kWh/klb =	104.0
Max. output capacity, kW =	26,000
Capacity factor =	.850
Purchase price, $/kWh =	.0520
Sales price, $/kWh =	.0520

ROM Coal Properties	
Ash fraction =	.080
Sulfur fraction =	.006
HHV, Btu/lb =	11,650
Price, $/MBtu =	1.20

Current Primary Fuel	
Gas price, $/MBtu =	2.81
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	2.81	15000.	1996.6	248.8	591.1	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
CFB cogen	.830	1.20	45000.	3529.4	783.0	1884.5	10067.0
Coal use, ton/yr = 126,229				Limestone use, ton/yr = 4,983			

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
		High Energy Escalation			
Gas boiler	54,285	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	17,932	3.027	7.8	42,384	1.281
		Medium Energy Escalation			
Gas boiler	44,183	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	14,552	3.036	7.9	39,257	1.125
		Zero Energy Escalation			
Gas boiler	34,782	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	7,939	4.381	7.4	32,519	1.070

McGUIRE AFB: 250 klb/h COGENERATION

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1153.8	900.0
Max. output capacity, MBtu/h =	288.5	90.0
Capacity factor =	.899	.495

Electric System	
Specific output, kWh/klb =	98.8
Max. output capacity, kW =	24,700
Capacity factor =	.886
Purchase price, $/kWh =	.0600
Sales price, $/kWh =	.0600

ROM Coal Properties	
Ash fraction =	.130
Sulfur fraction =	.020
HHV, Btu/lb =	12,800
Price, $/MBtu =	1.89

Current Primary Fuel	
Gas price, $/MBtu =	3.88
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	HTHW
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	3.88	0.	1892.8	228.6	564.1	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
CFB cogen	.830	1.89	45000.	5172.7	783.0	2281.0	11502.3

Coal use, ton/yr = 106,909 Limestone use, ton/yr = 14,067

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

Technology	Air Force Project: Life Cycle Cost, k$	Air Force Project: Benefit/ Cost Ratio	Air Force Project: Discounted Payback, yr	Private Project: Life Cycle Cost, k$	Private Project: Benefit/ Cost Ratio
		High Energy Escalation			
Gas boiler	39,674	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	25,835	1.536	17.0	50,382	.787
		Medium Energy Escalation			
Gas boiler	30,096	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	21,793	1.381	18.2	46,679	.645
		Zero Energy Escalation			
Gas boiler	21,185	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	12,649	1.675	16.3	37,679	.562

McGUIRE AFB: 250 klb/h COGENERATION, LOW COST OF MONEY

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1153.8	900.0
Max. output capacity, MBtu/h =	288.5	90.0
Capacity factor =	.899	.495

Electric System	
Specific output, kWh/klb =	98.8
Max. output capacity, kW =	24,700
Capacity factor =	.886
Purchase price, $/kWh =	.0600
Sales price, $/kWh =	.0600

ROM Coal Properties	
Ash fraction =	.130
Sulfur fraction =	.020
HHV, Btu/lb =	12,800
Price, $/MBtu =	1.89

Current Primary Fuel	
Gas price, $/MBtu =	3.88
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	HTHW
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	7.00
Private before-tax ROI, % =	14.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	3.88	0.	1892.8	228.6	564.1	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
CFB cogen	.830	1.89	45000.	5172.7	783.0	2281.0	11502.3

Coal use, ton/yr = 106,909 Limestone use, ton/yr = 14,067

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

Technology	Air Force Project: Life Cycle Cost, k$	Air Force Project: Benefit/ Cost Ratio	Air Force Project: Discounted Payback, yr	Private Project: Life Cycle Cost, k$	Private Project: Benefit/ Cost Ratio
		High Energy Escalation			
Gas boiler	60,345	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	23,807	2.535	13.4	55,835	1.081
		Medium Energy Escalation			
Gas boiler	43,885	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	17,988	2.440	13.7	50,472	.870
		Zero Energy Escalation			
Gas boiler	29,457	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	5,113	5.762	12.4	37,785	.780

PLATTSBURGH AFB: 250 klb/h COGENERATION

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1153.8	900.0
Max. output capacity, MBtu/h =	288.5	90.0
Capacity factor =	.913	.647

Electric System	
Specific output, kWh/klb =	98.8
Max. output capacity, kW =	24,700
Capacity factor =	.861
Purchase price, $/kWh =	.0630
Sales price, $/kWh =	.0600

ROM Coal Properties	
Ash fraction =	.090
Sulfur fraction =	.020
HHV, Btu/lb =	12,800
Price, $/MBtu =	1.97

Current Primary Fuel	
Gas price, $/MBtu =	.00
#6 Oil price, $/MBtu =	3.67

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	HTHW
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	.00	0.	.0	.0	.0	.0
#6 Oil boiler	.800	3.67	0.	2340.1	228.6	580.7	.0
CFB cogen	.830	1.97	45000.	5475.6	783.0	2302.3	11177.8

Coal use, ton/yr = 108,574 Limestone use, ton/yr = 14,286

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
High Energy Escalation					
Gas boiler	0	--			
#6 Oil boiler	42,199	1.000	<--- Existing system, primary fuel		
CFB cogen	31,214	1.352	17.8	55,713	.757
Medium Energy Escalation					
Gas boiler	0	--			
#6 Oil boiler	34,063	1.000	<--- Existing system, primary fuel		
CFB cogen	27,214	1.252	19.7	52,063	.654
Zero Energy Escalation					
Gas boiler	0	--			
#6 Oil boiler	24,799	1.000	<--- Existing system, primary fuel		
CFB cogen	17,703	1.401	17.4	42,804	.579

PLATTSBURGH AFB: 250 klb/h COGENERATION, LOW COST OF MONEY

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1153.8	900.0
Max. output capacity, MBtu/h =	288.5	90.0
Capacity factor =	.913	.647

Electric System	
Specific output, kWh/klb =	98.8
Max. output capacity, kW =	24,700
Capacity factor =	.861
Purchase price, $/kWh =	.0630
Sales price, $/kWh =	.0600

ROM Coal Properties	
Ash fraction =	.090
Sulfur fraction =	.020
HHV, Btu/lb =	12,800
Price, $/MBtu =	1.97

Current Primary Fuel	
Gas price, $/MBtu =	.00
#6 Oil price, $/MBtu =	3.67

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	HTHW
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	7.00
Private before-tax ROI, % =	14.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	.00	0.	.0	.0	.0	.0
#6 Oil boiler	.800	3.67	0.	2340.1	228.6	580.7	.0
CFB cogen	.830	1.97	45000.	5475.6	783.0	2302.3	11177.8

Coal use, ton/yr = 108,574 Limestone use, ton/yr = 14,286

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
			High Energy Escalation		
Gas boiler	0	--			
#6 Oil boiler	62,658	1.000	<--- Existing system, primary fuel		
CFB cogen	31,405	1.995	13.7	63,297	.990
			Medium Energy Escalation		
Gas boiler	0	--			
#6 Oil boiler	49,720	1.000	<--- Existing system, primary fuel		
CFB cogen	25,629	1.940	14.4	58,004	.857
			Zero Energy Escalation		
Gas boiler	0	--			
#6 Oil boiler	34,486	1.000	<--- Existing system, primary fuel		
CFB cogen	12,144	2.840	12.9	44,898	.768

PLATTSBURGH AFB: 250 klb/h COGENERATION, 8.5 M$ CAPITAL CREDIT

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1153.8	900.0
Max. output capacity, MBtu/h =	288.5	90.0
Capacity factor =	.913	.647

Electric System	
Specific output, kWh/klb =	98.8
Max. output capacity, kW =	24,700
Capacity factor =	.861
Purchase price, $/kWh =	.0630
Sales price, $/kWh =	.0600

ROM Coal Properties	
Ash fraction =	.090
Sulfur fraction =	.020
HHV, Btu/lb =	12,800
Price, $/MBtu =	1.97

Current Primary Fuel	
Gas price, $/MBtu =	.00
#6 Oil price, $/MBtu =	3.67

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	HTHW
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	.00	0.	.0	.0	.0	.0
#6 Oil boiler	.800	3.67	8500.	2340.1	228.6	580.7	.0
CFB cogen	.830	1.97	45000.	5475.6	783.0	2302.3	11177.8

Coal use, ton/yr = 108,574 Limestone use, ton/yr = 14,286

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
			High Energy Escalation		
Gas boiler	0	--			
#6 Oil boiler	49,224	1.000	<--- Existing system, primary fuel		
CFB cogen	31,214	1.577	12.9	55,713	.884
			Medium Energy Escalation		
Gas boiler	0	--			
#6 Oil boiler	41,088	1.000	<--- Existing system, primary fuel		
CFB cogen	27,214	1.510	13.7	52,063	.789
			Zero Energy Escalation		
Gas boiler	0	--			
#6 Oil boiler	31,824	1.000	<--- Existing system, primary fuel		
CFB cogen	17,703	1.798	11.8	42,804	.743

KELLY AFB: 250 klb/h COGENERATION

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1258.1	1050.0
Max. output capacity, MBtu/h =	314.5	105.0
Capacity factor =	.910	.427

Electric System	
Specific output, kWh/klb =	104.0
Max. output capacity, kW =	26,000
Capacity factor =	.917
Purchase price, $/kWh =	.0510
Sales price, $/kWh =	.0510

ROM Coal Properties	
Ash fraction =	.120
Sulfur fraction =	.013
HHV, Btu/lb =	12,300
Price, $/MBtu =	1.87

Current Primary Fuel	
Gas price, $/MBtu =	3.68
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	3.68	0.	1806.7	248.8	574.1	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
CFB cogen	.830	1.87	45000.	5648.9	783.0	2078.7	10651.7
Coal use, ton/yr = 122,797				Limestone use, ton/yr = 10,502			

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
		High Energy Escalation			
Gas boiler	38,421	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	34,954	1.099	25.8	59,343	.647
		Medium Energy Escalation			
Gas boiler	29,280	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	31,074	.942	>31	55,815	.525
		Zero Energy Escalation			
Gas boiler	20,773	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	21,410	.970	>31	46,501	.447

KELLY AFB: 250 klb/h COGENERATION, LOW COST OF MONEY

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	250.0	100.0
Delta enthalpy, Btu/lb =	1258.1	1050.0
Max. output capacity, MBtu/h =	314.5	105.0
Capacity factor =	.910	.427

Electric System	
Specific output, kWh/klb =	104.0
Max. output capacity, kW =	26,000
Capacity factor =	.917
Purchase price, $/kWh =	.0510
Sales price, $/kWh =	.0510

ROM Coal Properties	
Ash fraction =	.120
Sulfur fraction =	.013
HHV, Btu/lb =	12,300
Price, $/MBtu =	1.87

Current Primary Fuel	
Gas price, $/MBtu =	3.68
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Limestone inert fraction =	.050
Limestone price, $/ton =	20.80
Ash disp. price, $/ton =	7.80
AF discount rate, % =	7.00
Private before-tax ROI, % =	14.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Gas boiler	.800	3.68	0.	1806.7	248.8	574.1	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
CFB cogen	.830	1.87	45000.	5648.9	783.0	2078.7	10651.7

Coal use, ton/yr = 122,797 Limestone use, ton/yr = 10,502

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
		High Energy Escalation			
Gas boiler	58,366	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	36,706	1.590	17.8	68,399	.853
		Medium Energy Escalation			
Gas boiler	42,655	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	31,085	1.372	19.5	63,277	.674
		Zero Energy Escalation			
Gas boiler	28,883	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
CFB cogen	17,301	1.669	17.4	50,043	.577

GRIFFISS AFB: 290 klb/h COGENERATION

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	290.0	110.0
Delta enthalpy, Btu/lb =	1244.5	1050.0
Max. output capacity, MBtu/h =	360.9	115.5
Capacity factor =	.884	.503

Electric System	
Specific output, kWh/klb =	100.3
Max. output capacity, kW =	29,100
Capacity factor =	.872
Purchase price, $/kWh =	.0570
Sales price, $/kWh =	.0600

Stoker Coal Properties	
Ash fraction =	.080
Sulfur fraction =	.020
HHV, Btu/lb =	13,000
Price, $/MBtu =	1.70

Current Primary Fuel	
Coal price, $/MBtu =	1.70
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Lime inert fraction =	.050
Hydra. lime price, $/ton =	41.60
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Stoker boiler	.780	1.70	0.	1109.2	737.8	903.3	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
Stoker cogen	.800	1.70	33284.	5938.9	1241.6	2289.7	13337.2
Incr coal use, ton/yr = 109,270				Incr lime use, ton/yr = 6,832			

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
		High Energy Escalation			
Stoker boiler	23,997	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	14,008	1.713	13.5	32,945	.728
		Medium Energy Escalation			
Stoker boiler	23,821	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	9,330	2.553	11.2	28,658	.831
		Zero Energy Escalation			
Stoker boiler	22,276	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	-1,190	-18.717	8.5	18,289	1.218

GRIFFISS AFB: 290 klb/h COGENERATION, LOW COST OF MONEY

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	290.0	110.0
Delta enthalpy, Btu/lb =	1244.5	1050.0
Max. output capacity, MBtu/h =	360.9	115.5
Capacity factor =	.884	.503

Electric System	
Specific output, kWh/klb =	100.3
Max. output capacity, kW =	29,100
Capacity factor =	.872
Purchase price, $/kWh =	.0570
Sales price, $/kWh =	.0600

Stoker Coal Properties	
Ash fraction =	.080
Sulfur fraction =	.020
HHV, Btu/lb =	13,000
Price, $/MBtu =	1.70

Current Primary Fuel	
Coal price, $/MBtu =	1.70
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Lime inert fraction =	.050
Hydra. lime price, $/ton =	41.60
Ash disp. price, $/ton =	7.80
AF discount rate, % =	7.00
Private before-tax ROI, % =	14.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Stoker boiler	.780	1.70	0.	1109.2	737.8	903.3	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
Stoker cogen	.800	1.70	33284.	5938.9	1241.6	2289.7	13337.2

Incr coal use, ton/yr = 109,270 Incr lime use, ton/yr = 6,832

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
		High Energy Escalation			
Stoker boiler	33,645	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	10,600	3.174	10.9	35,111	.958
		Medium Energy Escalation			
Stoker boiler	33,347	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	3,868	8.621	9.5	28,903	1.154
		Zero Energy Escalation			
Stoker boiler	30,943	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	-10,933	-2.830	7.6	14,293	2.165

GRISSOM AFB: 158 klb/h COGENERATION

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	158.0	96.0
Delta enthalpy, Btu/lb =	1256.8	1050.0
Max. output capacity, MBtu/h =	198.6	100.8
Capacity factor =	.892	.521

Electric System	
Specific output, kWh/klb =	96.2
Max. output capacity, kW =	15,200
Capacity factor =	.865
Purchase price, $/kWh =	0450
Sales price, $/kWh =	.0450

Stoker Coal Properties	
Ash fraction =	.052
Sulfur fraction =	.008
HHV, Btu/lb =	11,300
Price, $/MBtu =	1.80

Current Primary Fuel	
Coal price, $/MBtu =	1.80
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Lime inert fraction =	.050
Hydra. lime price, $/ton =	41.60
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Stoker boiler	.800	1.80	0.	1035.1	448.0	706.2	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
Stoker cogen	.820	1.80	21758.	3406.0	663.8	1121.2	5182.9
Incr coal use, ton/yr = 58,283				Incr lime use, ton/yr = 0			

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YFAR = 1988)

Technology	Air Force Project: Life Cycle Cost, k$	Air Force Project: Benefit/ Cost Ratio	Air Force Project: Discounted Payback, yr	Private Project: Life Cycle Cost, k$	Private Project: Benefit/ Cost Ratio
		High Energy Escalation			
Stoker boiler	19,178	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	26,419	.726	>31	38,346	.500
		Medium Energy Escalation			
Stoker boiler	19,014	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	24,426	.778	>31	36,555	.520
		Zero Energy Escalation			
Stoker boiler	17,572	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	18,808	.934	>31	31,272	.562

GRISSOM AFB: 158 klb/h COGENERATION, LOW COST OF MONEY

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	158.0	96.0
Delta enthalpy, Btu/lb =	1256.8	1050.0
Max. output capacity, MBtu/h =	198.6	100.8
Capacity factor =	.892	.521

Electric System	
Specific output, kWh/klb =	96.2
Max. output capacity, kW =	15,200
Capacity factor =	.865
Purchase price, $/kWh =	.0450
Sales price, $/kWh =	.0450

Stoker Coal Properties	
Ash fraction =	.052
Sulfur fraction =	.008
HHV, Btu/lb =	11,300
Price, $/MBtu =	1.80

Current Primary Fuel	
Coal price, $/MBtu =	1.80
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Lime inert fraction =	.050
Hydra. lime price, $/ton =	41.60
Ash disp. price, $/ton =	7.80
AF discount rate, % =	7.00
Private before-tax ROI, % =	14.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Stoker boiler	.800	1.80	0.	1035.1	448.0	706.2	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
Stoker cogen	.820	1.80	21758.	3406.0	663.8	1121.2	5182.9
Incr coal use, ton/yr = 58,283				Incr lime use, ton/yr = 0			

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
			High Energy Escalation		
Stoker boiler	26,939	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	31,155	.865	>31	46,491	.579
			Medium Energy Escalation		
Stoker boiler	26,661	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	28,243	.944	>31	43,880	.608
			Zero Energy Escalation		
Stoker boiler	24,417	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	20,111	1.214	19.1	36,303	.673

WRIGHT-PATTERSON AFB: 450 klb/h COGENERATION

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	450.0	274.5
Delta enthalpy, Btu/lb =	1054.1	1050.0
Max. output capacity, MBtu/h =	474.4	288.2
Capacity factor =	.883	.559

Electric System	
Specific output, kWh/klb =	57.8
Max. output capacity, kW =	26,000
Capacity factor =	.814
Purchase price, $/kWh =	.0350
Sales price, $/kWh =	.0350

Stoker Coal Properties	
Ash fraction =	.060
Sulfur fraction =	.010
HHV, Btu/lb =	14,000
Price, $/MBtu =	1.79

Current Primary Fuel	
Coal price, $/MBtu =	1.79
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Lime inert fraction =	.050
Hydra. lime price, $/ton =	41.60
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Stoker boiler	.800	1.79	0.	3158.0	653.9	956.4	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
Stoker cogen	.820	1.79	15418.	8009.7	967.5	1582.1	6488.9

Incr coal use, ton/yr = 96,801 Incr lime use, ton/yr = 0

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

Technology	Air Force Project: Life Cycle Cost, k$	Air Force Project: Benefit/ Cost Ratio	Air Force Project: Discounted Payback, yr	Private Project: Life Cycle Cost, k$	Private Project: Benefit/ Cost Ratio
			High Energy Escalation		
Stoker boiler	42,802	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	60,907	.703	>31	69,643	.615
			Medium Energy Escalation		
Stoker boiler	42,300	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	57,817	.732	>31	66,973	.632
			Zero Energy Escalation		
Stoker boiler	37,902	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	45,567	.832	>31	56,083	.676

WRIGHT-PATTERSON AFB: 450 klb/h COGENERATION, LOW COST OF MONEY

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	450.0	274.5
Delta enthalpy, Btu/lb =	1054.1	1050.0
Max. output capacity, MBtu/h =	474.4	288.2
Capacity factor =	.883	.559

Electric System	
Specific output, kWh/klb =	57.8
Max. output capacity, kW =	26,000
Capacity factor =	.814
Purchase price, $/kWh =	.0350
Sales price, $/kWh =	.0350

Stoker Coal Properties	
Ash fraction =	.060
Sulfur fraction =	.010
HHV, Btu/lb =	14,000
Price, $/MBtu =	1.79

Current Primary Fuel	
Coal price, $/MBtu =	1.79
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Lime inert fraction =	.050
Hydra. lime price, $/ton =	41.60
Ash disp. price, $/ton =	7.80
AF discount rate, % =	7.00
Private before-tax ROI, % =	14.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Stoker boiler	.800	1.79	0.	3158.0	653.9	956.4	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
Stoker cogen	.820	1.79	15418.	8009.7	967.5	1582.1	6488.9

Incr coal use, ton/yr = 96,801 Incr lime use, ton/yr = 0

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
		High Energy Escalation			
Stoker boiler	60,381	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	82,022	.736	>31	92,350	.654
		Medium Energy Escalation			
Stoker boiler	59,531	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	77,369	.769	>31	88,404	.673
		Zero Energy Escalation			
Stoker boiler	52,686	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	59,070	.892	>31	72,438	.727

WRIGHT-PATTERSON AFB: 450 klb/h COGENERATION, 18.4 M$ CAPITAL CREDIT

INPUT PARAMETERS

Steam Conditions	HP Steam to Turbine	LP Steam to Heat System
Max. flow rate, klb/h =	450.0	274.5
Delta enthalpy, Btu/lb =	1054.1	1050.0
Max. output capacity, MBtu/h =	474.4	288.2
Capacity factor =	.883	.559

Electric System	
Specific output, kWh/klb =	57.8
Max. output capacity, kW =	26,000
Capacity factor =	.814
Purchase price, $/kWh =	.0350
Sales price, $/kWh =	.0350

Stoker Coal Properties	
Ash fraction =	.060
Sulfur fraction =	.010
HHV, Btu/lb =	14,000
Price, $/MBtu =	1.79

Current Primary Fuel	
Coal price, $/MBtu =	1.79
#6 Oil price, $/MBtu =	.00

Miscellaneous Parameters	
Heat sys. (Steam or HTHW) =	Steam
Labor rate, k$/person yr =	36.40
Lime inert fraction =	.050
Hydra. lime price, $/ton =	41.60
Ash disp. price, $/ton =	7.80
AF discount rate, % =	10.00
Private before-tax ROI, % =	17.00

CAPITAL AND ANNUAL COSTS (1988 DOLLARS)

Technology	Fuel/ Heat Eff	Fuel Price $/MBtu	Total Capital k$	Fuel k$/yr	Maint O & M k$/yr	Other O & M k$/yr	Elec Sales k$/yr
Stoker boiler	.800	1.79	18400.	3158.0	653.9	956.4	.0
#6 Oil boiler	.800	.00	0.	.0	.0	.0	.0
Stoker cogen	.820	1.79	15418.	8009.7	967.5	1582.1	6488.9

Incr coal use, ton/yr = 96,801   Incr lime use, ton/yr = 0

LIFE CYCLE COST ANALYSIS (DISCOUNTING BASE YEAR = 1988)

	Air Force Project			Private Project	
Technology	Life Cycle Cost, k$	Benefit/ Cost Ratio	Discounted Payback, yr	Life Cycle Cost, k$	Benefit/ Cost Ratio
			High Energy Escalation		
Stoker boiler	58,009	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	60,907	.952	.0	69,643	.833
			Medium Energy Escalation		
Stoker boiler	57,507	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	57,817	.995	.0	66,973	.859
			Zero Energy Escalation		
Stoker boiler	53,108	1.000	<--- Existing system, primary fuel		
#6 Oil boiler	0	--			
Stoker cogen	45,567	1.165	.0	56,083	.947

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